Ivanhoe Mines Ltd.

Financial Statements December 31, 2004 and 2003

...Ivanhoe Mines expects that initial commercial production from Oyu Tolgoi's Southern Oyu deposits could commence in mid-2007, with some underground ore being milled in 2008 from Hugo North's development activity.

— Corporate Strategy and Outlook

IVANHOE MINES

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CERTIFICATE OF HONOR

This Certificate of Honor is awarded by the Government of Mongolia
in appreciative public recognition of the
IVANHOE MINES
for their contribution to economic development and expansion of
Mongolia's reputation of being a trustworthy partner in the international
community through purchase of a treasury bill worth US$50 mln. which the
Government has repaid ahead of schedule in full , with interest payments
at the end of 2004.
The Ivanhoe Mines have confirmed the proverb
"A friend in need is a friend indeed" in reality.
The Government of Mongolia is grateful to the Ivanhoe Mines for their
generous assistance and full support of nation's economic growth.
Together We Make A Difference.

Presented to Robert Friedland, Chairman, Ivanhoe Mines
on this 26th day of January 2005
in Ulaanbaatar

PRIME MINISTER OF MONGOLIA — ELBEGDORJ TSAKHIA

"Ivanhoe Mines have confirmed the proverb, 'A friend in need is a friend indeed,' in reality"

— The Government of Mongolia honours Ivanhoe Mines

Ivanhoe Mines responded to a request from the Government of Mongolia in December, 2003, to help support the government's initiative to retire all of Mongolia's debt that was owed to the Russian Federation.

Ivanhoe, active in Mongolia since 1996, recognized the significance of the opportunity and purchased a one-year, US$50 million Mongolian Government Treasury Bill. With Ivanhoe's assistance, Mongolia was able to make a single payment of US$250 million to retire debt accumulated during the former Soviet era that totalled 11.4 billion transferable roubles – deemed equal to US$11.4 billion by the Paris Club.

Retirement of the large debt was a landmark act of independent nation building by Mongolia's leaders that removed a constraining financial burden from present and future generations of Mongolians.

In late December, 2004, the Mongolian Government completed repayment of Ivanhoe's Treasury Bill, ahead of schedule, plus US$1.34 million in interest.

The repayment of the Treasury Bill held by Ivanhoe demonstrated to the international business world that the Mongolian Government could be counted on to fulfill its obligations. It also further confirmed Mongolia as an attractive destination for responsive and environmentally responsible investment in the exploration and development of the nation's mineral endowment, which effectively expands the economy and benefits all Mongolians.

At a state ceremony in Ulaanbaatar on January 26, 2005, the Government of Mongolia paid special tribute to Ivanhoe Mines for its support. Prime Minister Tsakhia Elbegdorj presented a Certificate of Honor that said, in part: Ivanhoe Mines has confirmed the proverb, "A friend in need is a friend indeed," in reality.

The Ivanhoe management team, on behalf of all of our shareholders, remains deeply honoured.

Robert Friedland
Chairman, Ivanhoe Mines

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Management's Discussion and Analysis of Financial Condition and Results of Operations

(Stated in U.S. Dollars, except where noted)

INTRODUCTION

This discussion and analysis of the financial position and results of operations ("MD&A") of Ivanhoe Mines Ltd. should be read in conjunction with the audited consolidated financial statements of Ivanhoe Mines Ltd. and the notes thereto for the year ended December 31, 2004. In this MD&A, unless the context otherwise dictates, a reference to the Company refers to Ivanhoe Mines Ltd. and a reference to Ivanhoe Mines refers to Ivanhoe Mines Ltd. together with its subsidiaries and joint ventures. The effective date of this MD&A is March 21, 2005.

Additional information about the Company, including its Annual Information Form, is available at www.sedar.com.

FORWARD-LOOKING STATEMENTS

Except for statements of historical fact relating to Ivanhoe Mines, certain information contained herein constitutes forward-looking statements within the meaning of Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. Forward-looking statements include, but are not limited to, statements concerning estimates of expected capital expenditures, statements relating to expected future production and cash flows, statements relating to the continued advancement of Ivanhoe Mines' exploration, development and production projects, statements relating to the potential of the Oyu Tolgoi Project, statements relating to target milling rates and other statements that are not historical facts. When used in this document, the words such as "could," "plan," "estimate," "expect," "intend," "may," "potential," "should" and similar expressions, are forward-looking statements. Although Ivanhoe Mines believes that its expectations reflected in these forward-looking statements are reasonable, such statements involve risks and uncertainties and no assurance can be given that actual results will be consistent with these forward-looking statements. Important factors that could cause actual results to differ from these forward-looking statements include the potential that Ivanhoe Mines' projects will experience technological and mechanical problems, geological conditions in the deposits may not result in commercial levels of mineral production, changes in product prices, changes in political conditions, changes in the availability of project financing and other risks. Forward-looking statements are based on the opinions and estimates of management at the date the statements are made and are subject to a variety of risks and uncertainties and other factors that could cause actual events or results to differ materially from those projected in the forward-looking statements. The Company undertakes no obligation to update forward-looking statements if circumstances or management's estimates or opinions should change. The reader is cautioned not to place undue reliance on forward-looking statements.

This MD&A contains references to estimates of mineral resources. The estimation of resources is inherently uncertain and involves subjective judgments about many relevant factors. The accuracy of any such estimates is a function of the quantity and quality of available data, and of the assumptions made and judgments used in engineering and geological interpretation, which may prove to be unreliable. There can be no assurance that these estimates of mineral resources will be accurate or that such mineral resources can be mined or processed profitably. Mineral resources that are not mineral reserves do not have demonstrated economic viability. Factors that could cause actual results to differ materially include, but are not limited to, those set forth herein under "Risks and Uncertainties".

CORPORATE STRATEGY AND OUTLOOK

Ivanhoe Mines Ltd. is an international mining company currently focused on exploring and developing a major discovery of copper and gold at its Oyu Tolgoi (Turquoise Hill) project in southern Mongolia (the "Oyu Tolgoi Project"). Ivanhoe Mines' operations also include the extraction of copper from a 50% joint venture interest in the Monywa Copper Project in Myanmar.

Since its inception in 1994, mineral exploration has been the Company's main focus of interest. In 2005, the Company intends to devote most of its management and financial resources to furthering the exploration and development of the Oyu Tolgoi Project while at the same time continuing to explore for minerals in other parts of Mongolia, Eastern Asia and Australia. High priority also will be placed on fully understanding the extent, value and development potential of the strategically located coal resources recently uncovered on Ivanhoe Mines' exploration concessions in southern Mongolia.

In 2004, management expected to conclude the negotiations for its Stability Agreement with the Government of Mongolia, which is necessary to provide long-term investment security to finance the development of the Oyu Tolgoi Project. The life span of the Oyu Tolgoi Project is currently estimated to exceed 40 years, so the completion and execution of a satisfactory Stability Agreement that will crystallize such issues as taxes, power, labour, land use and water rights, is essential to allow the Company to finance the development of the Oyu Tolgoi Project. Management has provided a comprehensive briefing on the project to the Cabinet of the Mongolian government, in a public forum. Discussions are ongoing and the Company is hopeful that the Stability Agreement will be finalized and executed in 2005.

Rather than wait for the approval of the Stability Agreement, which would provide certainty for several key aspects required by a bankable feasibility study, the Company intends to release a revised preliminary assessment report (the Oyu Tolgoi "Integrated Development Plan"), late in Q2'05.

Findings from the two engineering studies that were initiated in 2004, the open pit feasibility study for the Southern Oyu deposits (which encompass the Southwest Oyu, South Oyu, Far South Oyu and Central Oyu deposits) and the underground pre-feasibility study for the large-scale underground block caving operation at the Hugo North deposit, will be integrated and combined within the economics of the Integrated Development Plan. The plan will address the proven and probable reserves at the Southwest Oyu deposit, the soon to be released independent estimate of indicated resources at the Hugo North deposit and the inferred resources at the Hugo North and the Hugo South deposits (the "Hugo Dummett" deposits). In management's view, the Integrated Development Plan will present a more informative, overall picture of the future development of the Oyu Tolgoi Project, especially given the recent exploration success in Hugo North and the expected 40 year mine life under the current plan. To bring the underground resources into a proven and probable category for feasibility purposes, actual underground development and characterization within the Hugo Dummett deposits is required. The exploration shaft and subsequent horizontal development will accomplish this requirement.

OYU TOLGOI PROJECT

Resource Delineation Drilling at Oyu Tolgoi

In 2004, the Company spent a total of $98.2 million in exploration, including $71.8 million on the Oyu Tolgoi Project. The Company's Southern Oyu deposits appear to have been largely defined. In contrast, at the Hugo Dummett deposits, drilling is ongoing and the Hugo North deposit remains open both at depth and to the north. The extent of mineralization contained in the Hugo North deposit has yet to be established.

In May and August of 2004, updated resource estimates, prepared by qualified independent geological consultants, were announced by the Company. The Company anticipates releasing an updated, independently prepared resource estimate for the Oyu Tolgoi Project in Q2'05.

Southern Oyu Resource Estimate

In August 2004, the Southern Oyu resource estimate included measured and indicated resources totalling 1.06 billion tonnes grading 0.48% copper, and 0.36 grams per tonne (gpt) gold, plus inferred mineral resources totalling 285 million tonnes grading 0.35% copper, and 0.23 gpt gold.

The measured and indicated resources were estimated using a 0.30% copper equivalent cut-off down to 560 metres below surface and a 0.60% copper equivalent cut-off below a depth of 560 metres. In addition to the measured and indicated resources, the Southern Oyu deposits' inferred resources were estimated to a maximum depth of 560 metres, using a 0.30% copper equivalent cut-off. The August 2004 resources estimate is separate and in addition to the resource estimates for the Hugo Dummett deposits released in May 2004.

Hugo Dummett Resource Estimate

In May 2004, the Hugo Dummett mineral resource was estimated to contain 1.16 billion tonnes of inferred resource grading 1.29% copper, and 0.23 gpt gold. The inferred resource was determined using a 0.60% copper equivalent cut-off grade.

In H2'04, Ivanhoe Mines' drilling efforts were concentrated on the Hugo North deposit, with an infill and step-out drilling program designed to expand the existing inferred resource base and, at the same time, upgrade a large percentage of the current inferred resource to the indicated category. Initially, the step-out drilling program was expected to be completed in early 2005, but additional drilling will be required throughout 2005 to define the ultimate extent of the Hugo North deposit and establish the degree of continuity, if any, of mineralization from the Hugo North deposit onto adjoining property held by Entrée Gold Inc. ("Entrée"). This infill drilling program, designed to bring a large portion of the Hugo North deposit to the indicated category, was completed in March 2005.

Shivee Tolgoi Property

On November 10, 2004, the Company closed an earn-in and equity participation agreement with Entrée to explore and potentially develop approximately 40,000 hectares of Entrée's Shivee Tolgoi property. A portion of the southern property boundary of Shivee Tolgoi is contiguous to the Hugo North deposit's northern property boundary. By spending $35 million over eight years, including $15 million in the first three years, the Company has the option to earn up to 80% in mineralization deeper than 560 metres and up to 70% in mineralization above the 560-metre level.

The Company also has the right to acquire all of Entrée's surface rights on the Shivee Tolgoi property by spending a minimum of $3 million in exploration expenditures in the first year and sufficient condemnation drilling to ensure that there is no economic mineralization below the surface of the areas directly affected.

The Company acquired 4.6 million units of Entrée for Cdn$4.6 million. Each unit consists of one Entrée common share and a warrant; each warrant entitles the holder to acquire, for a period of two years, one common share of Entrée at Cdn$1.10 per share.

Engineering and Development

The Company is focusing its engineering and metallurgical efforts on preparing the Oyu Tolgoi Integrated Development Plan. The Integrated Development Plan, expected to be released late in Q2'05, will combine the findings and economics of the feasibility study for an open-pit operation on the Southern Oyu deposits and the pre-feasibility study for a proposed underground mining operation in the Hugo North deposit. The accelerated development of the Hugo North enlarged deposit is the prime focus of the Integrated Development Plan and it represents a major change in development of the project recommended by the Preliminary Assessment report released in February 2004.

In January 2005, a 246-tonne bulk sample was collected from a 74-metre-deep shaft in the Southwest Oyu deposit. The samples were shipped from the Oyu Tolgoi site in January 2005 and pilot-plant trials on samples are expected to start in Q2'05 at an independent assay laboratory. The development strategy for the project is based on developing production from open-pit operations located within the Southern Oyu deposits and concurrently developing Hugo Dummett's underground resources to bring underground operations on stream as soon as possible.

The engineering for a 1,200-metre-deep exploration shaft was initiated in Q3'04, with the objective being to provide underground access to the Hugo South and Hugo North deposits and permit, for the purposes of the feasibility studies, further delineation and rock characterization of the underground mineral resources. The construction of the exploration shaft is expected to commence in Q2'05 and to be completed in early 2007; underground drifting activities from the shaft are expected to take place during the later part of 2007 and in 2008.

Completion of a feasibility study on the Hugo North deposit is expected in late 2008. Assuming timely completion of the Integrated Development Plan and the availability of project financing, Ivanhoe Mines expects that initial commercial production from Oyu Tolgoi's Southern Oyu deposits could commence in mid-2007, with some underground ore being milled in 2008 from Hugo North's development activity. Current estimates suggest that the development of the shallower Hugo South deposit will lag that of Hugo North. These plans remain subject to change based on unforeseen circumstances. There can be no assurance that a positive feasibility study or adequate project financing can be obtained by the dates estimated above, or at all.

Other Mongolian Exploration Activities

Ivanhoe Mines holds an extensive inventory of exploration leases in Mongolia totalling approximately 11.8 million hectares. The Company believes that these properties are prospective for gold and copper occurrences similar to its Oyu Tolgoi discovery, as well as metallurgical and thermal coal deposits that would be in close proximity to Chinese markets. In 2004, regional reconnaissance work, rock sampling, induced polarization surveys and diamond drilling were carried out mainly on the Kharmagtai property, the Bronze Fox District and the Nariin Sukhait property, a coal property located in the South Gobi Region of Mongolia. In December 2004, the Company announced its intention to initiate the development of what the Company currently believes to be extensive coal deposits in the South Gobi Region of Mongolia. Following a year-long evaluation of the coal-bearing basins in southern Mongolia, the Company has delineated three major coal opportunities located on lands wholly controlled by Ivanhoe Mines.

Ivanhoe's current mapping, surface sampling and drilling to date have established that the Nariin Sukhait coal mine, located approximately 40 kilometres from the Chinese border, is contained within the most southerly coal basin. The Nariin Sukhait mine, a relatively small property operated by an independent Mongolian-Chinese joint venture, adjoins and is completely surrounded by the Company's existing large land holdings. In 2004, the Nariin Sukhait operation started mining an outcropping seam with an estimated true thickness of approximately 60 metres. Current annual production for the mine is estimated at 450,000 tonnes of coal and is expected to increase to 2 million tonnes per year, upon completion of the construction of a 400-kilometre-long railway link on the Chinese side of the border.

In January 2005, the Company announced the start of a resource delineation drilling program to determine the extent and quality of coal that might be located on Ivanhoe Mines' property surrounding the Nariin Sukhait mine.

Strategic Alternatives

The Company continues to assess strategic alternatives for the development and financing of the Oyu Tolgoi Project. The Company's current plan is to aggressively advance the development of the project while continuing to discuss financing options with various parties.

In this regard, the Company is in discussions with major Chinese mining and financial companies, major Japanese mining and metal trading houses, other international mining companies and other third parties capable of financing the project, with a view to selecting suitable strategic partners to develop the Oyu Tolgoi Project and associated infrastructure. The Company believes that significant advantages could be realized from the participation of strategic partners and continues to assess opportunities, as they arise, to extend to one or more such partners a participating interest in the project. The Company is not soliciting bids from potential partners and has not set a deadline or target date for concluding any such agreement. Accordingly, there can be no assurance that any ongoing or future discussions will result in an agreement with a strategic partner or that the Company will pursue development of the Oyu Tolgoi Project with a strategic partner at all.

Stability Agreement

Negotiations are continuing with the Mongolian government for a long-term Stability Agreement. Through June 2004, the Company worked extensively with a formally designated working group established by the government for the purpose of negotiating and drafting a Stability Agreement. The agreement is expected to establish the critical terms and conditions that will apply to the Oyu Tolgoi Project during its developmental and operational phases. The Company believes that such an agreement will have a materially beneficial impact on its ability to obtain the financing necessary to develop the project. The agreement is expected to provide for stabilization of various matters within the parameters of existing Mongolian laws, including tax and fiscal issues, as well as other matters involving cross-border and import/export issues, confirmation and protection of appropriate mining, land and water licences, and development of critical infrastructure – including the supply of power – necessary to carry out exploration, mining, milling, processing and related activities over the life of the project.

In February 2005, the senior management team provided an extensive briefing on the Oyu Tolgoi Project to the Mongolian cabinet and interested government parties. The presentation was followed by a more than one hour long question and answer session. Subsequent to this meeting, a media briefing was organized by the government at which Ivanhoe Mines repeated the presentation to the media and non-governmental organizations. Again, this presentation was followed by a question and answer session. These events received broad coverage in the Mongolian media. At present, it appears that the Stability Agreement will be discussed again by the Cabinet of government before the end of the first quarter of 2005. No assurances can be given as to when, or if, Ivanhoe Mines' discussions will culminate in a Stability Agreement, or that any such Stability Agreement will contain terms and conditions that are, in all material respects, favourable to Ivanhoe Mines.

The Stability Agreement under negotiation is designed to follow the framework of current Mongolian laws. However, once this initial agreement is completed, the Company may, in the future, seek additional agreements and assurances from the government pertaining to the Oyu Tolgoi Project. Some of these agreements and assurances may involve matters beyond the parameters of existing Mongolian law and, as such, may require formal action by the Mongolian Parliament to amend current legislation or enact new legislation. However, no present assurance can be provided that any such additional agreements and assurances will be available when requested by Ivanhoe Mines, or at all.

MONYWA COPPER PROJECT

Assisted by higher copper prices, improved ore grades and higher copper production, the S&K Mine is continuing to generate excellent results. The Company expects to release in Q2'05 a two-step development plan that will combine the expansion of the existing operations at the S&K Mine with the development of the Letpadaung deposit (the "Monywa Copper Project"). This development plan is expected to be implemented over a period of five years, resulting in the Monywa Copper Project's overall copper cathode production capacity of 200,000 tonnes per year. In mid-October 2004, the mine's annual copper cathode throughput capacity increased to 39,000 tonnes (86 million pounds). All development costs were funded from the mine's internally generated cash flow.

- The first step in the plan, which is subject to an expected 2006 upgrade of the mine's power supply to 40 megawatts, is expected to take the mine's annual copper production from 39,000 tonnes to a projected rate of 50,000 tonnes (110 million pounds). This first step is expected to be put in place in H1'06.
- The second step, which is subject to a power supply of between 60 and 80 megawatts being made available, proposes to develop the nearby Letpadaung deposit over a four-year period. The proposed development will consist of the construction of three SX/EW modules, each with an annual capacity of 50,000 tonnes of copper cathode per year. Japanese, Korean and Chinese companies have made written expressions of interest to provide financing to fast-track the expansion of copper production for the Monywa Copper Project. Financing discussions are ongoing between these companies and the management of the Monywa Copper Project, although there are no assurances that satisfactory negotiations will be concluded.

BAKYRCHIK GOLD PROJECT

Engineering assessment and testing work continues on a proposal to produce up to 50,000 ounces of gold per year using a 150,000 to 200,000 tonnes per annum rotary kiln process. In an effort to minimize the mining risks at the start of operations, Bakyrchik engineers are assessing a plan to initially mine only from the surface by extending one of the existing open pits. Financing for the development is expected to come either from an initial public offering of equity securities by the Company's Bakyrchik subsidiary or some other form of third-party financing. There is no assurance that this financing initiative will be successful and lack of financing could delay or indefinitely postpone development.

CLONCURRY, AUSTRALIA

In Q1'05, following the completion of a 1,600-metre diamond drill program to test a 300-metre-wide by 400-metre-long magnetic anomaly on the Swan project, the Company announced the discovery of a new deposit of a potentially significant iron oxide copper-gold mineralization. The management of the Company believes that the area has excellent potential to host large-scale, high-grade iron oxide copper and gold deposits similar to the nearby Ernest Henry Mine, or the Olympic Dam Mine, in South Australia.

In 2005, Ivanhoe Mines is planning to recommence diamond drilling to further delineate the extent and grade of the underlying primary chalcocite and gold mineralization, and to conduct metallurgical testing on the supergene material to determine the heap-leach parameters of the near-surface, oxidized material. The Company has assembled a project development team, which includes the general manager and chief metallurgist who recently worked at the S&K Mine in Myanmar, to investigate the potential of quickly producing cathode copper from the supergene mineralization at the Swan deposit.

ASSET RATIONALIZATION

The Company is continuing to explore opportunities to rationalize non-core assets and is considering several potential disposition alternatives involving the outright or partial sale of non-core project interests, the formation of one or more joint ventures in respect of certain non-core projects or other transactions that would dilute or eliminate the Company's interest in, and relieve the Company of financial obligations in respect of, such non-core projects. The Company's principal objectives are to generate, or otherwise preserve, cash and to devote more managerial and financial resources to the Oyu Tolgoi Project. There can be no assurance that any disposition of non-core assets presently under consideration will occur on a timely basis, or at all. Pursuant to the Company's non-core asset disposal strategy, the Company sold its Savage River Mine in February 2005. See "Discontinued Operations" below.

DISCONTINUED OPERATIONS

In February 2005, the Company sold its Savage River operations for $21.5 million in cash, plus a series of contingent, escalating-scale annual payments based on sales and prices of iron ore pellets over the next five years (the "Deferred Cash Consideration"). The 2004 benchmark price for iron ore pellets was set at $38.10 per tonne. The following table lists the approximate Deferred Cash Consideration that may be received by the Company, based on the average future benchmark prices over the next five years:

Average benchmark pellet prices over next five years	Expected Deferred Cash Consideration
$40/tonne	$18.0 million
$60/tonne	$85.5 million
$70/tonne	$117.0 million

At the end of February 2005, a 71.5% increase in pellet prices for the April 2005 to March 2006 year was announced. Based on anticipated iron pellet prices of $65 per tonne and if the Savage River's pellet production is maintained over the next five years, the Company expects to receive a contingent payment of approximately $22.5 million by the end of March 2006 and an additional $79 million if iron pellet prices remain at this level for the next five years. Iron ore pellet prices are volatile, so there are no assurances that the unit prices negotiated for 2005 will be maintained over the next five years.

LIQUIDITY AND FUTURE FUNDING REQUIREMENTS

The Company's existing cash resources, together with the proceeds from the sale of the Savage River Mine, are expected to be sufficient to fund the Company's current and planned activities into the third quarter of 2005. Following completion of a feasibility study in respect of the Southern Oyu deposits, the Company expects to be in a position to seek project financing to implement its initial open-pit development plans at the Oyu Tolgoi Project. However, there can be no assurance that the Company will be able to obtain project financing before its existing cash resources are expended. See "Cash Resources and Liquidity."

Since its inception, the Company has relied on capital markets (and in particular, equity markets) to fund its exploration and other activities. If the Company's existing cash resources are insufficient to fund all of the Company's planned activities, or if the Company is unable to obtain project financing before its existing cash resources are expended, the Company will have to rely upon equity markets or other sources of capital (from potential joint venture partners or through other arrangements) – the availability of which cannot be assured – to continue funding the development of the Oyu Tolgoi Project. Capital markets are subject to significant volatilities and uncertainties.

There can be no assurance that Ivanhoe Mines' undeveloped or partially developed projects can be fully developed, in whole or in part, since factors beyond the Company's control may adversely affect its access to funding or its ability to recruit third-party participants.

SELECTED FINANCIAL INFORMATION

($ in millions of U.S. dollars, except per share information)

Years ended December 31,		2004		2003		2002
COPPER						
Revenue	$	44.1	$	22.9	$	20.2
Operating profit		27.5		5.0		4.7
Exploration expenses		98.2		68.0		33.9
General and administrative costs		22.8		17.4		12.3
Gain on sale of investments		4.5		4.6		0.5
Foreign exchange gain		4.4		12.4		0.3
Net (loss) from continuing operations		(98.3)		(68.3)		(46.5)
Net income (loss) from discontinued operations		8.6		(4.7)		15.5
Net (loss)		(89.6)		(73.0)		(31.0)
Net income (loss) per share						
Continuing operations	$	(0.35)	$	(0.28)	$	(0.24)
Discontinued operations	$	0.03	$	(0.02)	$	0.08
Total assets		460.9		455.7		276.0
Total long-term financial liabilities (including current portion of long-term debt)		8.9		17.2		24.2
CONTINUING OPERATIONS						
Capital expenditures		14.3		50.0		12.1
CONTINUING OPERATIONS						
Copper cathode – 50% share						
Units sold *(tonnes)*		15,730		13,808		13,875
Units produced *(tonnes)*		15,878		13,935		13,771
DISCONTINUED OPERATIONS						
Units sold *(tonnes pellets)*		2,118,197		2,180,000		2,269,773
AVERAGE SALE PRICE						
Copper cathode *(US$/pound)*	$	1.34	$	0.79	$	0.70

SELECTED QUARTERLY DATA

($ in millions of U.S. dollars, except per share information)

	Quarter Ended Mar-31	Jun-30	Sep-30	Dec-31	Year Ended Dec.31
2004					
Copper					
Revenue	9.4	10.8	9.8	14.1	44.1
Operating profit	5.9	6.9	5.9	8.8	27.5
General and administrative	(5.4)	(4.9)	(5.9)	(6.6)	(22.8)
Exploration expenses	(20.7)	(24.8)	(28.4)	(24.3)	(98.2)
Write-down of assets	—	—	—	(5.3)	(5.3)
Gain on sale of investments	1.2	3.3	—	—	4.5
Gain (loss) on foreign exchange	(1.8)	(1.4)	4.2	3.4	4.4
Net (loss) from continuing operations	(23.5)	(23.0)	(25.3)	(26.5)	(98.3)
Net income (loss) from discontinued operations	(4.4)	2.8	0.5	9.7	8.6
Net (loss)	(27.9)	(20.2)	(24.8)	(16.7)	(89.6)
Net income (loss) per share					
Continuing operations	$ (0.08)	$ (0.08)	$ (0.09)	$ (0.10)	$ (0.35)
Discontinued operations	$ (0.02)	$ 0.01	$ 0.00	$ 0.04	$ 0.03
Total	$ (0.10)	$ (0.07)	$ (0.09)	$ (0.06)	$ (0.32)
2003					
Copper					
Revenue	4.6	5.5	6.0	6.8	22.9
Operating profit (loss)	1.2	(2.7)	2.0	4.5	5.0
General and administrative	(3.0)	(3.3)	(4.0)	(7.1)	(17.4)
Exploration expenses	(10.8)	(15.2)	(20.8)	(21.2)	(68.0)
Write-down of assets	—	—	—	(1.2)	(1.2)
Gain on sale of investments	4.6	—	—	—	4.6
Gain (loss) on foreign exchange	2.6	5.9	(1.2)	5.1	12.4
Net (loss) from continuing operations	(7.9)	(16.6)	(27.3)	(16.5)	(68.3)
Net income (loss) from discontinued operations	(1.1)	(3.1)	0.3	(0.8)	(4.7)
Net (loss)	(9.0)	(19.7)	(27.0)	(17.3)	(73.0)
Net income (loss) per share					
Continuing operations	$ (0.04)	$ (0.07)	$ (0.11)	$ (0.06)	$ (0.28)
Discontinued operations	$ (0.00)	$ (0.01)	$ 0.00	$ (0.01)	$ (0.02)
Total	$ (0.04)	$ (0.08)	$ (0.11)	$ (0.07)	$ (0.30)

EXECUTIVE SUMMARY – 2004 YEAR

The Company recorded a net loss of $89.6 million (or $0.32 per share) in 2004, compared to a net loss of $73 million (or $0.30 per share) in 2003. Major factors in the 2004 results included an operating profit from mining operations totalling $27.5 million and exploration expenses of $98.2 million. Exploration expenditures were primarily incurred on the Oyu Tolgoi (Turquoise Hill) Project and other projects in Mongolia. The increase in exploration expenses is attributed to Ivanhoe's drilling activities on the Oyu Tolgoi Project, especially on the Hugo Dummett deposits, and the engineering expenses related to the Integrated Development Plan that combines the findings and economics from the open-pit feasibility study and the underground pre-feasibility study.

CORPORATE

- In February 2005, the Company sold the Savage River operations for a guaranteed cash payment of $21.5 million plus a series of contingent, escalating-scale annual payments based on future pellet prices. The escalating-scale payments, made over a five-year period, will begin in March 2006. The conclusion of negotiations between the two largest iron ore producers and the Japanese steel mills was announced at the end of February 2005. For the iron ore year starting on April 1, 2005, the iron ore pellet price benchmark of $38.10 was increased by 71.5%, to approximately $65 per tonne. As a result of this increase, the Company expects to receive cumulative payments totalling approximately $44 million by the end of March 2006. In addition, if the $65 a tonne benchmark price and Savage River's pellet production are maintained over the next five years, the Company expects to receive additional consideration totalling approximately $79 million.
- In December 2003, Ivanhoe purchased a $50 million one-year Treasury Bill issued by the Government of Mongolia as part of the government's retirement of its Soviet-era debt to the Russian Federation. Through a series of partial principal and interest payments, the Treasury Bill was completely repaid by the end of 2004.
- In July 2004, the Company completed an equity financing by issuing 20 million common shares for gross proceeds of Cdn$140 million.
- On January 18, 2005, the common shares of the Company were listed on the New York Stock Exchange under the new trading symbol IVN. The Company concurrently de-listed from Nasdaq. The shares of the Company also have been listed on the Toronto Stock Exchange since 1996. The listing on the Australian Stock Exchange is expected to terminate in Q2'05.
- During 2004, the Company, with the assistance of its strategic financial advisors, continued to evaluate alternatives for the development of financing of the Oyu Tolgoi Project.
- During 2004, Ivanhoe Mines was engaged in ongoing discussions with several major, Asia-based international mining finance institutions concerning project financing and off-take arrangements in connection with the proposed development of the Oyu Tolgoi Project.
- In November 2004, the Company announced a Cdn$4.6 million equity investment in Entrée, as well as a $35 million earn-in participation agreement on Entrée's mineral interests, a portion of which is adjacent to the northern boundary of the Hugo North deposit at Oyu Tolgoi. The agreement also granted the Company surface access rights on Entrée's property.

MONGOLIA

During 2004, Ivanhoe spent a total of $85.5 million on exploration and development of its Mongolian copper and gold projects, most of which was invested in the Oyu Tolgoi discovery. To date, Ivanhoe has expensed all exploration, development and engineering costs related to its Mongolian projects. In March 2004, the discovery of the Hugo Dummett deposits at Oyu Tolgoi was recognized as the most significant, recent mineral discovery in the world during the annual conference of the Prospectors and Developers Association of Canada, in Toronto.

Resource Studies

The Company released the results of a resource estimate for the Hugo Dummett deposits in May 2004. The inferred resources were estimated using a 0.60% copper equivalent cut-off grade.

In August 2004, the Company released the results of a new independent resource estimate for the Southern Oyu deposits. The measured and indicated resources were estimated using a 0.30% copper equivalent cut-off down to 560 metres below surface and a 0.60% copper equivalent cut-off below a depth of 560 metres. In addition to the measured and indicated resources, the Southern Oyu deposits' inferred resources were estimated to a maximum depth of 560 metres using a 0.30% copper equivalent cut-off. The August 2004 resources estimate is separate and in addition to the resource estimate for the Hugo Dummett deposits released in May 2004.

The Company expects the release of an updated, independent resource estimate for the Oyu Tolgoi Project in Q2'05.

	Million tonnes	Copper (%)	Gold (g/t)
May 2004 resource estimate – Hugo Dummett deposits			
Inferred	1,160	1.29	0.23
August 2004 resource estimate – Southern Oyu deposits			
Measured and indicated	1,061	0.48	0.36
Inferred[1]	285	0.35	0.23

[1] Inferred resources are separate and in addition to the measured and indicated resources figures.

Engineering Studies and Development

In February 2004, Ivanhoe released an independently prepared Preliminary Assessment report on the Oyu Tolgoi Project that confirmed its potential to become a new, long-life copper and gold mine that could rank among the largest in the world. Ongoing engineering studies initiated in 2004, following the release of this Preliminary Assessment report and drilling results from the Hugo North deposit, have modified the development plans proposed by the Preliminary Assessment report in a major way. See "Exploration – Oyu Tolgoi Studies". Electronic copies of the Preliminary Assessment report are available at www.sedar.com.

In Q3'04, the Company announced its intention to complete and release, by late Q2'05, the Integrated Development Plan, a study that will combine the findings and economics of two studies: the Southern Oyu open pit feasibility study and the underground pre-feasibility study on the Hugo North deposit. The feasibility study focused on a detailed, baseline evaluation of initial facilities required to mine and process material from the open-pittable resources contained in the Southern Oyu deposits at a nominal rate of 70,000 tonnes per day, and incremental throughput tonnages above this base.

In January 2005, a 246-tonne bulk sample was shipped to an assay laboratory for pilot-plant trials. In Q3'04, the Company initiated the engineering for the construction of a 1,200-meter-deep exploration shaft intended to provide underground access to the Hugo North and Hugo South deposits and permit delineation and rock characterization of the underground mineral resources in the deposits. The construction of the exploration shaft is expected to commence in Q2'05 and to be completed in early 2007. Underground drifting activities from the shaft are expected to take place during the later part of 2007 and during 2008.

Stability Agreement

Negotiations are continuing with a formally designated working group of the Mongolian government for a long-term stability agreement. That agreement is expected to establish the critical terms and conditions that will apply to the Oyu Tolgoi Project during its development and operational phases. Although the stability agreement negotiations were delayed by the June 2004 national elections in Mongolia, the Company expects to successfully finalize these negotiations in 2005. Following the completion of the Stability Agreement, the Company may seek additional agreements and assurances from the government pertaining to the Oyu Tolgoi Project. Some of these agreements and assurances may involve matters beyond the parameters of existing Mongolian law and, as such, may require formal action by the Mongolian Parliament to amend current legislation or enact new legislation.

MONGOLIA – OTHER PROJECTS

In December 2004, Ivanhoe Mines successfully traced a thick seam of coal onto property 100%-owned and controlled by the Company in the South Gobi Region of Mongolia, approximately 40 kilometres north of the Mongolia-China border. Five core holes drilled by Ivanhoe Mines intersected the same seam that is currently being mined by an independent Mongolian-Chinese joint venture on a small licence area (the Nariin Sukhait Mine) surrounded by Ivanhoe's extensive land interests. The coal seam, one of five conformable seams identified to date at Nariin Sukhait, has been mapped in outcrop and sub-crop throughout a major coal basin that stretches a total of 120 kilometres east and west of the mine, on ground controlled by Ivanhoe.

In December 2004, the Company also announced that it had retained Citibank as its advisor in broad-ranging discussions with various parties about the future of the Tavan Tolgoi coal deposit, 140 kilometres northwest of the Oyu Tolgoi Project. The Company is exploring the possibility of a joint development of the Tavan Tolgoi coal deposit in conjunction with the development of the Oyu Tolgoi Project.

In November 2004, the Company's exploration team discovered four significant, gold-rich copper porphyry targets in the newly named Bronze Fox District in southern Mongolia. The discoveries are approximately 140 kilometres northeast of the Oyu Tolgoi Project and 430 kilometres south-southeast of Ulaanbaatar.

INNER MONGOLIA, CHINA

Throughout 2004, Ivanhoe Mines continued its extensive reconnaissance programs to identify high-priority targets based upon geologic models developed at Oyu Tolgoi and other epithermal-style deposits. In January 2005, the Company was able to obtain the transfer of six exploration licences into Ivanhoe Mines' Yahao joint venture and a 30-year permanent Business Licence. Ivanhoe Mines has the right to earn interests ranging from 80% to 90% from mineral projects developed from the exploration and mining licences held by the Yahao joint venture.

MYANMAR

The Company's share of net income from the Monywa Copper Project joint-venture in Myanmar totalled $22.1 million in 2004, compared to a net profit of $2.1 million in 2003. The S&K Mine produced 31,756 tonnes of copper cathode in 2004 (15,878 tonnes net to Ivanhoe), an increase of approximately 14% over 2003. The average copper price received in 2004 was $1.34 a pound, compared to $0.79 a pound in 2003. Minegate cash costs in 2004 were approximately 44 cents a pound. Copper production for 2005 is estimated to be 38,000 tonnes at minegate cash costs of approximately 43 cents a pound. In 2004, the project received a premium of approximately $60 per tonne of copper (three cents a pound) for its LME Grade A quality. This premium was increased to $125 per tonne in 2005.

KAZAKHSTAN

During 2004, the Bakyrchik operation re-processed material from the tailings pond. Several gravity tables were purchased and assembled in the second half of 2004 and 22,000 tonnes of tailings material were processed in Q4'04. Engineering assessment and pilot test work continued on a proposed 150,000- to 200,000-tonne per annum rotary kiln process designed to yield annual gold production of up to 50,000 ounces of gold. In 2005, the Company is planning to obtain funding from outside investors to finance Bakyrchik's expansion plans.

CLONCURRY, AUSTRALIA

In Q1'05 the Company announced the discovery of a new deposit of a potentially significant iron oxide copper-gold mineralization at the Swan prospect. The new discovery, located 600 metres southwest of the former Mount Elliott gold and copper mine, has a 300-metre-wide by 400-metre-long magnetic anomaly signature. A total of six diamond drill holes, one of which reached a depth of at least 350 metres below surface, encountered chalcocite and gold mineralization. The mineralization is open-ended along strike and to depth. The management of Ivanhoe Mines believes that the area has excellent potential to host large-scale, high-grade iron oxide copper and gold deposits similar to the nearby Ernest Henry Mine, or the Olympic Dam Mine, in South Australia.

In 2005, Ivanhoe Mines is planning to recommence diamond drilling to further delineate the extent and grade of the underlying primary chalcocite and gold mineralization, and to conduct metallurgical testing on the supergene material to determine the heap-leach parameters of the near-surface, oxidized material. The Company has assembled a project development team, which includes the general manager and chief metallurgist who recently worked at the S&K Mine in Myanmar, to investigate the potential of quickly producing cathode copper from the supergene mineralization at the Swan deposit.

QUARTERLY ANALYSIS Q4'04 VS. Q4'03

Revenue

In Q4'04, revenue from the S&K Mine increased by 107% over the same period in 2003. This increase was due to a 20% increase in tonnage sold and a 70% increase in copper prices.

Operating Profit

In Q4'04, total operating costs before inventory adjustments increased by 20%, compared to the same period in 2003. The increase was mainly attributable to a 17% increase in cathode production. In Q4'03, the total recoverable metal contained in the heaps was adjusted upward, resulting in a significant one-time reduction in operating costs for that quarter.

Exploration

Total exploration expenses in Q4'04 increased by approximately 15% over the same period in 2003. Exploration expenditures were primarily incurred on the Oyu Tolgoi Project and other projects in Mongolia. The increase in exploration expenses over the last two years was a result of Ivanhoe Mines' accelerated drilling activities on the Oyu Tolgoi project, especially on the Hugo Dummett deposits, and the engineering costs related to the Integrated Development Plan.

Administrative Costs

Administrative costs in Q4'04 were slightly lower, but consistent with expenditures in Q4'03.

Net Income (Loss) from Discontinued Operations

The Company announced the sale of the Savage River mine operations in February 2005 and consequently the 2004 and 2003 operating results from the mine have been reclassified as net income (loss) from discontinued operations.

Income from the Savage River mine operations totalled $9.7 million in Q4'04, compared to a loss of $0.8 million in Q4'03. During Q4'04, approximately one-third of total metal volumes sold by the Savage River operations was set at spot-market rates at almost double the normal contract price. In addition to the higher sales price received in Q4'04, gains resulting from the foreign exchange hedge program put in place by the mine at the end of Q3'04 also contributed to the higher earnings for the quarter.

Foreign Exchange Gain

In Q4'04, the Company maintained most of its cash resources in Canadian dollars ("Cdn$"). The foreign exchange gain during the quarter was mainly attributable to the strengthening of the Canadian dollar against the U.S. dollar.

REVIEW OF OPERATIONS

A) EXPLORATION

Exploration expenses in 2004 totalled $98.2 million, compared to $68.0 million in 2003. The $30.2 million increase in costs was mainly due to the cost of engineering evaluation studies initiated in 2004 on the Oyu Tolgoi Project and increased drilling and exploration activities on the Oyu Tolgoi Project and other Mongolian properties.

a) Oyu Tolgoi Project, Mongolia

At the end of 2004, Ivanhoe Mines held four mining licences at Oyu Tolgoi totalling approximately 24,000 hectares. Ivanhoe Mines also held directly, and indirectly with Asia Gold Corp. ("Asia Gold"), a 51%-owned subsidiary of the Company, interests in exploration licences covering approximately 11.8 million hectares. In 2004, Ivanhoe Mines spent $85.5 million on its Mongolian properties. The main focus of exploration activities was the Oyu Tolgoi project ($71.8 million), the Kharmagtai project ($2.5 million), the Bronze Fox District ($0.5 million), and licence holding fees and general reconnaissance projects ($10.7 million). In 2003, Ivanhoe Mines spent $59.5 million on its Mongolian properties.

i) Oyu Tolgoi Exploration

In February 2004, the Company released a Preliminary Assessment report, referred to as the scoping study. The Preliminary Assessment report included inferred resources that had not been sufficiently drilled to have economic considerations applied to them to enable them to be used as the foundation necessary to develop a feasibility study.

Drilling Program (Southwest Oyu, South Oyu, Far South Oyu and Central Oyu Deposits). Following the release of the Preliminary Assessment report, an infill drilling program was initiated on the Central Oyu, Southwest Oyu and South Oyu deposits with the objective to upgrade a significant portion of the open pit inferred resources to the measured and indicated categories. The program was completed in July 2004. On August 18, 2004, a new independent resource estimate was released by AMEC E&C Services Limited. The total measured and indicated resource was estimated at 1.06 billion tonnes grading 0.47% copper and 0.36 grams of gold (g/t) per tonne. The cut-off grade used for this estimate was 0.30% copper equivalent for resources up to 560 metres below surface and 0.60% copper equivalent for resources at depths exceeding 560 metres. This resource estimate provided the Company with an independently based foundation for the design and optimization of the open pits that will form part of the feasibility study for the Southern Oyu deposits.

Drilling Program (Hugo Dummett Deposits). In the second half of 2004, Ivanhoe Mines' drilling efforts were concentrated on the Hugo Dummett deposits to continue the infill drilling and exploratory program designed to expand the existing inferred resource base. The drilling program's main focus is to upgrade a large percentage of the current inferred resource to the indicated category. The drilling program initially was expected to be completed in early 2005, but additional drilling will be required throughout 2005 to cover the enlargement of the Hugo North Deposit and establish the degree of continuity, if any, of mineralization from Hugo North onto the adjoining Entrée property.

The most recent resource estimate for the Hugo Dummett deposits completed in May 2004 included inferred resources of 1,160 million tonnes grading 1.29% copper and 0.23 g/t gold, using a 0.60% copper equivalent cut-off grade. The May 2004 inferred resources estimate for the Hugo Dummett deposits was separate and in addition to the previously mentioned resource estimate for the Southern Oyu deposits. The Company expects to release an updated independent resource estimate in Q2'05.

ii) Oyu Tolgoi Studies

Scoping study. The Preliminary Assessment report released in February 2004 recommended a two-stage approach to the development of the Oyu Tolgoi Project. The total capital cost for the first stage was estimated at approximately $529 million.

Feasibility Study, Southern Oyu Deposits. In Q3'04, the Company announced its intention to complete and release, by late Q2'05, the Integrated Development Plan, a study that will combine the findings and economics of two studies: the Southern Oyu open pit feasibility study and the underground pre-feasibility study on the Hugo North deposit. The feasibility study focused on a detailed baseline evaluation of initial facilities required to mine and process material from the open-pittable resources contained in the Southern Oyu deposits at a nominal rate of 70,000 tonnes per day, and incremental throughput tonnages above this base. In the second half of 2004, the preliminary design of the processing facility was sufficiently developed to enable equipment pricing to be obtained and to provide material take-offs for estimating purposes.

At the end of 2004, the Company had completed the preliminary design of infrastructure, including the design of the water supply system, the design of tailings storage facilities and the design of on-site support facilities, such as offices, accommodations and workshops. Various studies aimed at optimizing the process flow sheet and site layout were undertaken and the results will be used in the next phase of work to finalize designs and estimates. Construction of the bulk-sample shaft commenced in Q3'04 and the shaft's targeted depth of approximately 70 metres was reached in January 2005. Samples from the shaft were extracted and shipped to the assay laboratory in January 2005, allowing pilot-plant trials to commence in Q2'05.

Pre-feasibility Study, Hugo North Deposit. In the second half of 2004, work on the pre-feasibility study mainly focused on engineering and cost analysis related to the underground block-cave mining of higher-grade sections of the Hugo North deposit at rates up to 85,000 tonnes per day. Drilling during the second half of 2004 focused on infill drilling of the initial production zone at Hugo North.

The contract for a 1,200-metre exploration shaft and lateral developments that will provide underground access to the Hugo South and Hugo North deposits was awarded to a major international shaft-sinking firm in Q3'04. As part of the planning for construction of the exploration shaft, long-lead items were identified and necessary orders, either to purchase or manufacture the required equipment, were placed. During Q4'04, equipment for a quarry and batch plant was purchased and construction of surface works is planned for early 2005. The geotechnical drilling program was completed during Q4'04 and a final analysis and recommendations are expected in early 2005.

Water Supply. The investigation of reliable water resources for the Oyu Tolgoi Project has identified two major sedimentary groundwater aquifers within 60 kilometres of the project site. The hydrogeological investigations aimed at defining the water supply for Oyu Tolgoi and the preparation of models to confirm the ability of the aquifers to provide the required water supply were completed by the end of 2004.

Metallurgical Work. By the end of 2004, all samples for flotation testwork and testing of composites representing time periods of production were completed for the Southwest Oyu and South Oyu deposits. Batch flotation tests for the variability samples from the Southwest and South deposits were more than two-thirds complete. To assess various marketing criteria, concentrate samples representative of the first 10 years of production were obtained from a small flotation pilot plant.

iii) Shivee Tolgoi earn-in agreement with Entrée Gold Inc.

On November 10, 2004, the Company closed an earn-in and equity participation agreement with Entrée to explore and potentially develop approximately 40,000 hectares of Entrée's Shivee Tolgoi property. A portion of the Shivee Tolgoi's southern property boundary is contiguous to Hugo North deposit's northern property boundary. By spending $35 million over eight years, including $15 million in the first three years, the Company has the option to earn up to 80% in mineralization deeper than 560 metres and up to 70% in mineralization above the 560-metre level.

The Company also has the right to acquire all of Entrée's surface rights on the Shivee Tolgoi property by spending a minimum of $3 million in exploration expenditures in the first year and sufficient condemnation drilling to ensure that there is no economic mineralization below the surface of the areas directly affected.

The Company acquired 4.6 million units of Entrée for Cdn$4.6 million. Each unit consists of one Entrée common share and a warrant; each warrant entitles the holder to acquire, for a period of two years, one common share of Entrée at Cdn$1.10 per share.

b) Other Mongolian Copper/Gold Exploration Projects

In 2004, regional reconnaissance work, rock sampling, induced polarization surveys and diamond drilling was carried out, mainly on the Kharmagtai property and the Bronze Fox District.

c) Mongolian Coal Projects

In December 2004, the Company announced its intention to initiate the development of what the Company currently believes to be extensive coal deposits in the South Gobi Region of Mongolia. Following a year-long evaluation of the coal-bearing basins in southern Mongolia, the Company has delineated three major coal-bearing basins located on lands 100% controlled by Ivanhoe Mines.

The Nariin Sukhait open pit mine, located within the most southerly basin and currently being mined by an independent Mongolian-Chinese joint venture, started mining in 2004 on an outcropping seam with an estimated true thickness of approximately 60 metres. The Nariin Sukhait mining licences, located approximately 40 kilometres from the Chinese border, are contained within a small area adjacent to and completely surrounded by property controlled by Ivanhoe Mines. Current annual production for the mine is estimated at approximately 450,000 tonnes of coal and is expected to increase to two million tonnes per year upon completion of the construction of a 400-kilometre-long railway link on the Chinese side of the border.

Ivanhoe's current mapping, surface sampling and drilling to date have established that the bulk of the coal basin that contains the Nariin Sukhait mine is within Ivanhoe Mines' current exploration licences. In January 2005, the Company announced the start of a resource delineation drilling program to determine the extent and quality of coal that might be located on Ivanhoe Mines' property surrounding the Nariin Sukhait mine.

In December 2004, the Company also announced that it had retained Citibank as its advisor in broad-ranging discussions with various parties about the future of the Tavan Tolgoi coal deposit, located 140 kilometres northwest of the Oyu Tolgoi Project. The Company is exploring the possibility of a joint development of the Tavan Tolgoi coal deposit in conjunction with the development of the Oyu Tolgoi Project.

d) Other

i) China: Jinshan Gold Mines Inc.

Ivanhoe Mines is exploring for gold, copper and platinum-group metals in several provinces of China through a series of joint ventures with Jinshan Gold Mines Inc. (formerly Pacific Minerals Inc.) ("Jinshan"). In Q3'04, Jinshan initiated a pilot test program for a large-scale, heap-leach operation on its most advanced project, the 217 Gold Project in Inner Mongolia. The Company's share of Jinshan's exploration expenditures in 2004 totalled $1.9 million. At the end of 2004, the Company held 18.7 million common shares (38.5%) of Jinshan.

ii) Inner Mongolia, China: Ivanhoe Mines

Throughout 2004, Ivanhoe Mines continued its extensive reconnaissance programs to identify high-priority targets based upon geologic models developed at Oyu Tolgoi and other epithermal-style deposits. In January 2005, the Chinese Ministry of Land & Resources authorized the transfer of six exploration licences into Ivanhoe Mines' Yahao joint venture. The joint venture also obtained from the Inner Mongolia provincial government a 30-year permanent Business Licence. Ivanhoe Mines has the right to earn interests ranging from 80% to 90% in mineral projects developed under the exploration and mining licences held by the Yahao joint venture.

The six exploration licences are evenly split among the following three projects: the Siwumuchang gold-silver project, the Whu Zhu Er Ga Shun copper-gold project and the Ba Ri Tu nan gold-silver project. Ivanhoe Mines also is maintaining its efforts to obtain approval from the local government authorities for the transfer of various exploration licences into the Oblaga joint venture. Inner Mongolia exploration expenditures in 2004 totalled approximately $3.0 million in exploration activities and $1.2 million in property acquisition payments.

iii) Cloncurry, Australia

The Cloncurry leases cover an area of approximately 1,450 square kilometres, located 160 kilometres southeast of Mount Isa in northwestern Queensland. The areas surrounding the Cloncurry property are prospective for copper and gold, with potential for other minerals, such as cobalt, lead, zinc and silver. The objective of the exploration program in 2004 was to locate large, shallow mineral occurrences amenable to a heap-leaching open pit operation. A 17-hole, 3,549-metre drilling program was completed at Mt Doré in 2004 and a seven-hole, 1,071–metre drilling program was completed in Q4'04 at the Swan prospect. Progress was made during the year to establish relationships with indigenous title claimants to advance exploration agreements on various exploration leases. Expenditures in 2004 totalled approximately $4.8 million.

In Q1'05, the Company announced the discovery of a new deposit of a potentially significant iron oxide copper-gold mineralization at the Swan prospect. The new discovery, located 600 metres southwest of the former Mount Elliott gold and copper mine, has a 300-metre-wide by 400-metre-long magnetic anomaly signature. A total of six diamond drill holes, reaching a depth of at least 350 metres below surface, encountered chalcocite and gold mineralization. The mineralization is open-ended along strike and to depth. Ivanhoe Mines' management believes that the area has excellent potential to host large-scale, high-grade iron oxide copper and gold deposits similar to the nearby Ernest Henry Mine, or the Olympic Dam Mine, in South Australia.

In 2005, Ivanhoe Mines is planning to recommence diamond drilling to further delineate the extent and grade of the underlying primary chalcocite and gold mineralization, and to conduct metallurgical testing on the supergene material to determine the heap-leach parameters of the near-surface, oxidized material. The Company has assembled a project development team, which includes the general manager and chief metallurgist who recently worked at the S&K Mine in Myanmar, to investigate the potential of quickly producing cathode copper from the supergene mineralization at the Swan deposit.

iv) Kazakhstan: Bakyrchik

In 2004, the Bakyrchik operation re-processed material from the tailings pond. Based on favorable results, additional gravity tables were purchased and assembled in Q4'04 and the initial 14,000 tonnes processed in Q3'04 were increased to 22,000 tonnes in Q4'04. Engineering assessment and pilot test work continued on a proposed 150,000- to 200,000-tonne-per-annum rotary kiln process designed to yield annual gold production of up to 50,000 ounces. Bakyrchik engineers also are assessing a proposal to mine gold by extending one of the existing open pits. A National Instrument 43-101 qualified report has been commissioned from a third-party engineering firm to evaluate this plan. If realized, the potential to start commercial operations with surface ore rather than underground-mined ore would reduce the start-up risk of the mining part of the project. Bakyrchik expenditures during 2004, including engineering, assessment work and mine care and maintenance costs, totalled approximately $3.8 million (2003 – $3.4 million).

Summary of exploration expenditures by project:

Years ended December 31,	2004	2003	2002
Total exploration expenditures *($000)*	$ 98,174	$ 67,989	$ 33,934
PERCENTAGE ALLOCATION *(%)*			
Mongolia	87	87	81
China	3	5	1
Myanmar	3	4	7
Bulgaria	1	—	—
Australia	5	—	—
Korea	—	3	8
Other	1	1	3
	100	100	100

B) MINING OPERATIONS

Monywa Copper Project (S&K Mine), Myanmar

	Total Operation			Company's 50% net share		
Year ended December 31,	2004	2003	% Increase (decrease)	2004	2003	% Increase (decrease)
Total tonnes moved[1] *(Tonnes (000's))*	10,675	18,527	(42)			
Tonnes of ore to heap *(Tonnes (000's))*	6,881	8,767	(22)			
Ore grade *(CuCN %)*	0.65	0.60	8			
Strip ratio *(Waste/Ore)*	0.45	0.92	(51)			
Cathode production *(Tonnes)*	31,756	27,869	14	15,878	13,935	14
Tonnage sold *(Tonnes)*	31,460	27,615	14	15,730	13,808	14
Average sale price received ($/pound)				$ 1.34	$ 0.79	69
Sales *($(000))*				44,091	22,866	93
Cost of operations *($(000))*				11,412	12,428	(8)
Operating profit *($(000))*				27,502	4,954	455

[1] Includes ore and waste material

Copper prices on the London Metal Exchange averaged $1.30 per pound in 2004, compared to $0.81 per pound in 2003.

In 2004, the cash component of cost of operations increased by 16% ($1.8 million) over 2003. The increase in costs was mainly attributable to increased unit power costs, higher commercial and import taxes, increased chemical costs and higher road maintenance charges. This increase in costs is net of a 49% reduction in equipment rental charges ($2.4 million), mainly attributable to lower tonnage moved.

Assisted by higher copper prices, improved ore grades and higher copper production, the S&K Mine is continuing to generate excellent results. The Company expects to release in Q2'05 a two-step development plan that combines the expansion of the existing operations at the S&K Mine with the development of the Letpadaung deposit. This development plan is expected to be implemented over a period of five years, resulting in the Monywa Copper Project's overall copper cathode production capacity of 200,000 tonnes per year. In mid-October 2004, the mine's annual copper cathode throughput capacity increased to 39,000 tonnes (86 million pounds). All development costs were funded from the mine's internally generated cash flow.

- The first step of the plan, which is subject to an expected 2006 upgrade of the mine's power supply to 40 megawatts, is expected to take annual copper production from the S&K Mine's deposit to a projected rate of 50,000 tonnes (110 million pounds). This first step is expected to be put in place in H1'06.
- The second step, which is subject to a power supply of between 60 and 80 megawatts being made available, proposes to develop the Letpadaung deposit over a four-year period. The proposed development will consist of the construction of three SX/EW modules, each with an annual capacity of 50,000 tonnes of copper cathode per year. Japanese, Korean and Chinese companies have made written expressions of interest in providing financing to fast-track the expansion of copper production from the S&K Mine and Letpadaung deposits. Financing discussions are ongoing between these companies and the management of the Monywa Copper Project, although there are no assurances that satisfactory negotiations will be concluded.

Each phase of the expansion is expected to be funded from internally generated cash flows. The Monywa Copper Project also is considering external funding alternatives that would enable accelerated expansion. See "Corporate Strategy and Outlook – Monywa Copper Project".

C) DISCONTINUED OPERATIONS

Savage River Mine, Tasmania

Year ended December 31,	2004	2003	% Increase (decrease)
Total volumes moved[1] *(BCM (000's))*	9,310	10,007	(7)
Tonnes milled *(000's)*	5,336	5,308	1
Strip ratio *(Tonnes waste/tonnes ore)*	4.4	5.5	(21)
Concentrate production *(Tonnes (000's))*	2,106	2,286	(8)
Iron ore content *(Fe%)*	29.9	32.6	(8)
Pellet production *(Tonnes)*	2,102,863	2,255,938	(7)
Pellet sales *(Tonnes)*	2,118,197	2,180,000	(3)
Sales *($/tonne)*	$ 40	$ 31	29
($(000))	83,898	66,833	26
Cost of operations *($(000))*	71,614	63,480	13
Operating profit (loss) *($(000))*	7,915	(1,952)	506
Average foreign exchange rate *(US$/AUD$)*	0.7370	0.6529	13

[1] Includes ore and waste material

Net income from discontinued operations was approximately $8.6 million in 2004, compared to a net loss of $4.7 million in 2004. The 29% increase in the unit sale price resulted from the 19% increase in the approved pellet price for 2004, plus higher prices obtained in Q4'04 from the pellet and concentrate sales negotiated at spot prices, which reached almost double the established standard rate for the year. Net operating profit was affected by a 14% increase in operating costs, mainly attributable to higher wages, electricity, fuel and gas charges.

On February 28, 2005, the Company completed of the sale of its total investment and loans to the Savage River operations for two initial cash payments totalling $21.5 million, plus a series of contingent, escalating-scale annual payments based on the annual pellet price. The escalating payments will be made over five years, commencing March 2006. A 71.5% increase in the iron ore price benchmark for the 2005 year was announced at the end of February 2005. Based on this expected increase, the Company expects to receive by the end of March 2006, cumulative payments totalling approximately $44.0 million. In addition, if the 2005 newly increased pellet price benchmark and the Savage River pellet production are maintained over the following five years, the Company should receive additional payments totalling approximately $79 million. Total pellet production for 2005 is estimated to be approximately 2.0 million tonnes.

D) ADMINISTRATIVE AND OTHER

General and Administrative

The $5.4 million increase in General and Administrative expenditures in 2004 was primarily due to a $2.8 million increase in stock-based compensation and increases in wages and benefits, insurance, travel charges and legal expenses.

Foreign Exchange Gains

In 2004 and 2003, the Company maintained most of its cash resources in Canadian dollars. The majority of the foreign exchange gains in 2004 and 2003 were attributable to the strengthening of the Canadian dollar against the U.S. dollar.

Gain on Sale of Investments

The $4.5 million gain on sale of investments in 2004 consisted of a $3.3 million gain from the sale of the Company's property interest located in Vietnam and a $1.2 million gain from the sale of the Resource Investment Trust share investment. The $4.6 million gain on sale of an investment in 2003 resulted from the sale of the Company's shares of Emperor Mines Limited.

Share of Loss on Significantly Influenced Investees

At December 31, 2004, the Company held 38.5% (2003 – 35.5%) of Jinshan's common shares (see "Review of Operations – Exploration, Other-China: Jinshan Gold Mines Inc."), and consequently $2.0 million (2003 – $2.3 million) of the $2.3 million (2003 – $2.4 million), represented the expensing by the Company of its share of Jinshan's net loss.

Write Down of Assets

In 2004, the Company recorded a $5.3 million write-down reflecting an impairment of a portion of Jinshan's original underlying assets at the date of the Company's investment in Jinshan. In 2003, following the sale of its Korean assets to Asia Gold, the Company wrote down its investment in its Korean assets by $1.2 million.

Dilution Gain on Investment in Subsidiary

Starting in Q3'03, following the acquisition by the Company of more than 50% of the outstanding common shares of Asia Gold, the financial results of Asia Gold were consolidated in the Company's financial results. In 2003, a $4.2 million dilution gain was recognized by the Company following Asia Gold's initial public offering.

Share Capital

At March 21, 2005, the Company had a total of 293.8 million common shares and the following purchase warrants outstanding:

Share purchase warrants outstanding	Maturity date	Exercise price per share	Total number of shares to be issued
7.125 million[1]	December 19, 2005	Cdn$12.50	7.125 million
5.76 million[2,3]	February 15, 2006	$8.68	0.576 million

[1] Each warrant entitles the holder to acquire one common share.

[2] Each 10 warrants entitle the holder to acquire one common share.

[3] In 2005, the expiry date was extended from February, 2005 to February, 2006.

At March 21, 2005, the Company had a total of approximately 8.8 million incentive stock options outstanding, with a weighted average exercise price per share of Cdn$5.49. Each option is exercisable to purchase a common share of the Company at prices ranging from Cdn$1.20 to Cdn$12.70 per share.

CASH RESOURCES AND LIQUIDITY

At December 31, 2004, consolidated working capital was $142.5 million, including cash of $122.6 million, compared with working capital of $128.1 million and cash of $107.0 million at December 31, 2003.

Operating Activities

The $99.2 million in cash used in operating activities in 2004 was primarily the result of $98.2 million in exploration expenditures.

Investing Activities

After repayment of the $50 million Mongolian Treasury Bill in Q4'04, a total of $39.3 million in cash was used in investing activities in 2004. The main cash expenditures included $8.2 million in sustaining capital expenditures on mining property, plant and equipment; $5.4 million in non-producing mining plant and equipment on exploration projects, primarily located in Mongolia and Australia, and $20.8 million on the acquisition of various mineral interests, consisting mainly of the second $20.0 million installment of the $37.0 million purchase price for the BHP royalty interest acquisition in Q4'03.

Financing Activities

Financing activities in 2004 consisted mainly of net proceeds totalling $100.6 million from the 20.0 million common shares issued at a price of $5.32 (Cdn$7.00) per share in July 2004, less $15.0 million of debt repayments by the S&K Mine ($7.5 million net to Ivanhoe Mines).

The $100.6 million equity financing raised at the end of June 2004 allocated $90.9 million in expenditures to the Oyu Tolgoi Project ($82.2 million) and to exploration activities on various projects in China ($8.7 million). A total of approximately $58 million was spent or incurred in the second half of 2004 on these various projects. Within the first four months of 2005, the Company anticipates spending on these projects the remaining portion of the equity financing.

The Company's existing cash resources, together with the proceeds from the sale of the Savage River Mine, are expected to be sufficient to fund the Company's current and planned activities into the third quarter of 2005. Following completion of the Integrated Development Plan, the Company expects to be in a position to seek project financing to implement its initial open-pit development plans at the Southern Oyu deposits.

However, there can be no assurance that the Company will be able to obtain project financing before its existing cash resources are exhausted. Failure to generate sufficient funding from one or more of these sources may require Ivanhoe Mines to delay, postpone or curtail certain of its planned activities for the second half of 2005 and thereafter.

Proceeds received from the sale of the Savage River mine will be used to supplement the funding of the Company's ongoing activities at Oyu Tolgoi, although there can be no assurance that these funds, if and when received, will be sufficient to meet all of the Company's funding requirements.

The Company expects to fund additional planned expenditures for the second half of 2005 and beyond from external sources, which may include debt or equity financing, proceeds from the sale of existing non-core assets, third-party participation in one or more of the Company's projects, or a combination thereof. There can be no assurance that the Company will be successful in generating sufficient funds from any of these sources. Failure to generate sufficient funding from one or more of these sources may require Ivanhoe Mines to delay, postpone or curtail certain of its planned activities in 2005, and thereafter. Over the long term, the Company will need to obtain additional funding for, or third-party participation in, its undeveloped or partially developed projects (including the Oyu Tolgoi Project, the Company's other Mongolian exploration projects, its Chinese and Australian exploration projects and the Bakyrchik project) to bring them into full production (see "Risks and Uncertainties – Additional Funding Requirements").

CONTRACTUAL OBLIGATIONS

US$(000)

Payments due in years ending December 31,	2005	2006	2007	2008	2009	2010+	Total
Long term debt[1]	$ 7,500	$ —	$ —	$ —	$ —	$ —	$ 7,500
Operating leases[2]	629	349	158	56	—	—	1,192
Purchase obligations[2]	13,934	—	—	—	—	—	13,934
Other long-term obligations[3]	432	724	432	7,503	—	9,739	18,830
	22,495	1,073	590	7,559	—	9,739	41,456
ALLOCATION							
S&K Mine	8,187	432	432	5,355	—	—	14,406
Mongolia	13,763	440	148	50	—	—	14,401
Bakyrchik	—	—	—	—	—	9,739	9,739
Cloncurry	—	—	—	2,148	—	—	2,148
Singapore	172	201	10	6	—	—	389
Vancouver	373	—	—	—	—	—	373
	22,495	1,073	590	7,559	—	9,739	41,456

[1] This amount is included in the Company's Consolidated Balance Sheet as at December 31, 2004 and excludes future interest payments.

[2] These amounts mainly represent various long-term contracts that include commitments for future operating payments under contracts for drilling, engineering, equipment purchases, rentals and other arrangements.

[3] Other long-term obligations mainly consist of deferred royalty payments and asset retirement obligations.

In 1997, the S&K Mine entered into an agreement for the sale of a guaranteed quantity of Grade A Product (as defined in the agreement) from the mine to Marubeni Corporation, which is affiliated with one of the lenders of the project financing. This agreement is expected to expire by the end of 2005.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in conformity with generally accepted accounting principles in Canada requires companies to establish accounting policies and to make estimates that affect both the amount and timing of the recording of assets, liabilities, revenues and expenses. Some of these estimates require judgments about matters that are inherently uncertain.

A detailed summary of all of the Company's significant accounting policies and the estimates derived therefrom is included in Note 2 to the annual Consolidated Financial Statements for the year ended December 31, 2004. While all of the significant accounting policies are important to the Company's consolidated financial statements, the following accounting policies and the estimates derived therefrom, have been identified as being critical:

- Carrying Values of Mining Property, Plant and Equipment and Other Mineral Property Interests;
- Depletion and Depreciation of Property, Plant and Equipment;
- Heap Inventory Valuation;
- Asset Retirement Obligations;
- Income Taxes.

Carrying Values of Mining Property, Plant and Equipment and Other Mineral Property Interests

The Company undertakes a review, at least annually, to evaluate the carrying values of operating mines and other mineral property interests. Preparation of a life-of-mine's cash flow for each remaining year is based on management's estimates of remaining mine reserves and grade, future production and sale volumes, unit sales prices, future operating and capital costs and reclamation costs to the end of mine life. For each mining project, the carrying value is compared to the estimated future discounted cash flows and any excess is written down against operations.

The estimates used by management are subject to various risks and uncertainties. It is reasonably possible that changes in estimates could occur which may affect the expected recoverability of the Company's investments in mining projects and other mineral property interests.

Depletion and Depreciation of Property, Plant and Equipment

Mining property, plant and equipment comprise the largest component of Ivanhoe Mines' assets and, as such, the amortization of these assets has a significant effect on the Company's financial statements.

On the commencement of commercial production, depletion of each mining property is provided on the unit-of-production basis using estimated proven and probable reserves as the depletion basis. The mining plant and equipment and other capital assets are depreciated, following the commencement of commercial production, over their expected economic lives using either the unit-of-production method or the straight-line method (over two to 15 years), as appropriate.

Capital projects in progress are not depreciated until the capital asset has been put into operation.

The proven and probable reserves are determined based on a professional evaluation using accepted international standards for the assessment of mineral reserves. The assessment involves the study of geological, geophysical and economic data and the reliance on a number of assumptions. The estimates of the reserves may change, based on additional knowledge gained subsequent to the initial assessment. This may include additional data available from continuing exploration, results from the reconciliation of actual mining production data against the original reserve estimates, or the impact of economic factors such as changes in the price of commodities or the cost of components of production. A change in the original estimate of reserves would result in a change in the rate of depletion and depreciation of the related mining assets, or could result in impairment, resulting in a write-down of the assets.

Following the start of commercial production, some mining companies' accounting policies are to expense all costs of removing waste material. Many mining companies, including Ivanhoe Mines, have adopted a different accounting policy whereby, for the entire mine life, the costs of removing waste rock at open-pit mines, commonly referred to as "stripping costs," are deferred. For Ivanhoe Mines, mining costs associated with waste-rock removal are deferred or accrued, as appropriate, and charged to operations on the basis of the average stripping ratio for each mine area. The average stripping ratio is calculated as the ratio of the tonnes of waste material estimated to be mined to the estimated recoverable tonnes of metals from that mine area. The policy of deferring stripping costs results in the smoothing of costs of removing waste material over the life of the mine rather than expensing those actual costs in the period incurred.

The following is a summary of strip ratios for the S&K Mine[1]:

ACTUAL	
2002	0.73
2003	0.92
2004	0.45
FORECAST	
2005	0.79
2006	1.11
2007	1.10
Life of mine average	0.97

[1] The strip ratio is calculated using tonnes of waste mined over tonnes of ore mined.

Heap Inventory Valuation

Ivanhoe Mines' copper operations involve the process of stacking ore on heaps and extracting a copper-bearing solution from the heaps using a continuous leaching process. The inventory categorized as "broken ore on leach pads" represents the inventory cost of estimated recoverable copper quantities contained in the heaps. It is not practical in a normal mine operation to obtain direct measurements of these quantities of recoverable copper. Instead, remaining metal inventory quantities are estimated indirectly by subtracting total copper production from the cumulative estimate of recoverable copper stacked on the heaps.

A decrease in the estimated copper quantities recoverable from the heaps would directly increase the cost of copper production and decrease the value of broken ore on leach pads.

Each month, the broken ore on leach pads is valued at the lower of the weighted average cost of production and net realizable value. The monthly cost of production includes all costs related to mining for the month, including allocated depreciation and depletion charges. All of this ore has been classified as a current asset since, based on historical leaching data, the copper is expected to be recovered within the next 12 months. The estimated units of copper on the leach pads are based on the amount of ore placed on the pads, the expected recovery rates and actual production.

Copper recovery rates are dependent on whether the ore is processed before it is stacked on the heaps. Copper recoveries from crushed and agglomerated ore material are approximately 80% and the leach cycle takes almost a year to complete. The leaching cycle for run-of-mine material – unprocessed material deposited directly on the heaps – is much shorter, (approximately 160 days), but the copper percentage recovery rate is normally lower and is approximately 75 %.

At December 31, 2004, the total amount of recoverable metal contained in the heaps was estimated at approximately 31,700 tonnes of copper (net 16,850 tonnes to Ivanhoe Mines), at a cost of approximately $631 per tonne, or $0.29 per pound of copper.

Ivanhoe Mines reviews the estimated units of copper on the heap-leach pads on a regular basis and, where appropriate, revises its estimates of those quantities to recognize changes in the expected recovery rates based on actual recoveries.

Asset Retirement Obligations

The Company has obligations for site restoration and decommissioning related to its mining properties. The Company, using mine closure plans or other similar studies that outline the requirements planned to be carried out, estimates the future obligations for mine closure activities. Because the obligations are dependent on the laws and regulations of the countries in which the mines operate, the requirements could change – resulting from amendments in those laws and regulations relating to environmental protection and other legislation affecting resource companies.

Ivanhoe Mines recognizes liabilities for statutory, contractual or legal obligations associated with the retirement of mining property, plant and equipment when those obligations result from the acquisition, construction, development or normal operation of the assets. Initially, a liability for an asset retirement obligation is recognized at its fair value in the period in which it is incurred. Upon initial recognition of the liability, the corresponding asset retirement cost is added to the carrying amount of the related asset and the cost is amortized as an expense over the economic life of the asset using either the unit-of-production method or the straight-line method, as appropriate. Following the initial recognition of the asset retirement obligation, the carrying amount of the liability is increased for the passage of time and adjusted for changes to the amount or timing of the underlying cash flows needed to settle the obligation.

Because the estimate of obligations is based on future expectations in the determination of closure provisions, management makes a number of assumptions and judgments. The closure provisions are more uncertain the further into the future the mine closure activities are to be carried out. Actual costs incurred in future periods in relation to the remediation of Company's existing assets could differ materially from the $17.4 million undiscounted future value of Ivanhoe Mines' estimated asset retirement obligations at December 31, 2004.

Income Taxes

The Company must make significant estimates in respect of the provision for income taxes and the composition of its future income tax assets and future income tax liabilities. Ivanhoe Mines' operations are, in part, subject to foreign tax laws where interpretations, regulations and legislation are complex and continually changing. As a result, there are usually some tax matters in question which may, on resolution in the future, result in adjustments to the amount of future income tax assets and future income tax liabilities, and those adjustments may be material to the Ivanhoe Mines' financial position and results of operations.

Future income tax assets and liabilities are computed based on differences between the carrying amounts of assets and liabilities on the balance sheet and their corresponding tax values, using the enacted or substantially enacted, as applicable, income tax rates at each balance sheet date. Future income tax assets also result from unused loss carry-forwards and other deductions. The valuation of future income tax assets is reviewed quarterly and adjusted, if necessary, by use of a valuation allowance to reflect the estimated realizable amount.

The determination of the ability of the Company to utilize tax loss carry-forwards to offset future income taxes payable requires management to exercise judgment and make assumptions about the future performance of the Company. Management is required to assess whether the Company is "more likely than not" to be able to benefit from these tax losses. Changes in economic conditions, metal prices and other factors could result in revisions to the estimates of the benefits to be realized or the timing of utilizing the losses.

Recent Accounting Pronouncements

As part of its agenda, the Emerging Issues Task Force of the U.S. Financial Accounting Standards Board is reviewing several accounting issues related to the mining industry. Should this result in changes to U.S. Generally Accepted Accounting Principles ("GAAP"), Canadian GAAP may also be changed in an effort to harmonize with U.S. GAAP.

RISKS AND UNCERTAINTIES

Material risks and uncertainties affecting Ivanhoe Mines, their potential impact, and the Company's principal risk management strategies, are as follows.

Additional Funding Requirements

The further development and exploration of the various mineral properties in which it holds interests depends upon Ivanhoe Mines' ability to obtain financing through joint ventures, debt financing, equity financing or other means. Ivanhoe Mines must arrange significant project financing for development of the Oyu Tolgoi Project. There can be no assurance that Ivanhoe Mines will be successful in obtaining any required financing as and when needed. Depressed markets for precious and base metals may make it difficult, or impossible, for Ivanhoe Mines to obtain debt financing or equity financing on favorable terms, or at all. Ivanhoe Mines operates in a region of the world that is prone to economic and political upheaval and certain mineral properties held by Ivanhoe Mines are located in politically and economically unstable countries, which may make it more difficult for Ivanhoe Mines to obtain debt financing from project lenders. Failure to obtain additional financing on a timely basis may cause Ivanhoe Mines to postpone its development plans, forfeit rights in some or all of its properties or joint ventures, or reduce or terminate some or all of its operations.

Risks Pertaining to Mongolia

Mongolia is, and for the foreseeable future is expected to remain, the country in which Ivanhoe Mines concentrates most of its business activities and financial resources. Since 1990, Mongolia has been in transition from state socialism and a planned economy to a political democracy and a free market economy. Much progress has been made in this transition, but much more progress remains to be made, particularly with respect to the rule of law. Many laws have been enacted, but in many instances they are neither understood nor enforced. For decades, Mongolians have looked to politicians and bureaucrats as the sources of the "law". This has changed in theory, but often not in practice. With respect to most day-to-day activities in Mongolia, government civil servants interpret, and often effectively make, the law. This situation is gradually changing, but at a relatively slow pace. Laws may be applied in an inconsistent, arbitrary and unfair manner and legal remedies may be uncertain, delayed or unavailable.

Ivanhoe Mines' current focus is the Oyu Tolgoi Project. Ivanhoe Mines is engaged in discussions with a working group of Mongolian government representatives aimed at reaching a long-term stability agreement establishing the critical terms and conditions that will apply to the Oyu Tolgoi Project during its operational phase. Management believes that such an agreement (or lack thereof) will have a material impact on Ivanhoe Mines' ability to obtain the financing necessary to develop the project. The stability agreement that Ivanhoe Mines is seeking from the Mongolian government is expected to address tax and fiscal issues, as well as other matters, including cross-border and import/export issues and confirmation of appropriate mining, land and water licence tenures and infrastructure necessary to carry out all exploration, mining, milling, processing and related activities over the life of the project. No assurances can be given as to when, or if, Ivanhoe Mines' discussions with the Mongolian government working group will culminate in a stability agreement, or that any such stability agreement will contain terms and conditions that are, in all material respects, favourable to Ivanhoe Mines.

Uncertainties Related to Mineral Resource Estimates

There is a degree of uncertainty attributable to the calculation of mineral resources and corresponding grades being mined or dedicated to future production. Until resources are actually mined and processed, the quantity of resources and grades must be considered as estimates only. In addition, the quantity and value of reserves or resources may vary, depending on metals prices. Any material change in the quantity of resources, grades or stripping ratio may affect the economic viability of Ivanhoe Mines' properties. In addition, there can be no assurance that metal recoveries in small-scale laboratory tests will be duplicated in larger-scale tests under on-site conditions, or during production. Deferred Cash Considerations expected to be received by the Company from the sale of the Savage River mine are based both future iron pellet prices (see below) and on current estimated mineral reserves and anticipated future annual production from the mine. There is no guarantee that these mineral reserves and annual production estimates and the estimated Deferred Cash Considerations will be realized. See "Corporate Strategy and Outlook – Discontinued Operations".

Metal Price Volatility

Copper and iron-ore pellet prices are subject to volatile price changes from a variety of factors, including international economic and political trends, expectations of inflation, global and regional demand, currency-exchange fluctuations, interest rates and global or regional consumption patterns, speculative activities and increased production due to improved mining and production methods. The supply of, and demand for, Ivanhoe Mines' principal products – iron ore and copper – is affected by various factors, including political events, economic conditions and production costs.

Unlike most metals, iron ores are not fungible commodities, as each is somewhat different in composition and usage characteristics. The iron-ore market behaves like a product, rather than a commodity, market, with zones of competition and zones of exclusion. The market is one of direct customer-to-producer relationships, without middlemen, warehousing or buffer stocks, speculators or futures market. The market is imperfect and oligopolistic. Prices are not set by the market clearance principle, but to optimize returns to producers within the constraint of the total market size. Iron ore pellet prices are negotiated once a year and have risen sharply in recent years, increasing approximately 10% in 2003, a further 19% in 2004 and a recently announced 71% in 2005. In the past, iron ore pellet prices have suffered significant declines and there is no guarantee that the current upward trend in pellet prices will continue in the future.

In the second half of 2003, copper prices benefited from speculative buying activity from hedge funds in anticipation of a global economic turnaround that has yet to fully materialize. China's ever-expanding need to import various metals to feed its buoyant economy also contributed to the sharp increase in prices in 2003 and 2004 for copper and iron ore.

Prior to 2003, many metal prices, when adjusted for inflation, were in a downward trend. Although many analysts now forecast that metal prices are expected to increase in the near future, there is no assurance that the 2003 and 2004 increases in metal prices represent a turning point or a confirmation of a reversal of that previously established downward trend in metal prices.

Ivanhoe Mines did not hedge any metal sales or production in 2003 and 2004 and has no plans to do so in 2005.

Operating Risks

Ivanhoe Mines faces a number of potential risks with respect to the proposed expansion at the Monywa Copper Project, which includes the development of the nearby Letpadaung deposit. Myanmar's current power-generating ability is limited and there can be no assurance that improvements to Myanmar's national power system, sufficient to furnish the additional required power for the planned expansion of the S&K Mine operations, will be made on a timely basis, or at all. If not, it may be necessary to construct a local source of power, which may not be feasible or which may render the project uneconomic.

The high-lift leach piles planned for the S&K Mine and the Letpadaung deposit carry technical risks. These risks include geotechnical failure, chemical degradation of the heap material, compaction and loss of permeability, lack of oxygen, excessive iron build-up and excessive acid generation. Manifestation of these risks could adversely affect the level of copper recoveries and increase operating costs.

Although Ivanhoe Mines believes that the material to be extracted from the Letpadaung deposit will exhibit the same heap-leaching characteristics as the ore currently being mined at the S&K Mine, this assumption cannot be confirmed prior to mining. Different metallurgical characteristics in the Letpadaung deposit, if and to the extent they might exist, could adversely affect the technical feasibility and economics of the S&K Mine's Letpadaung development plans.

Ivanhoe Mines conducts its operations in several countries through co-operative joint ventures with government-controlled entities. While this connection benefits Ivanhoe Mines in some respects, there is a substantial inequality with respect to the influence of the parties with the applicable government. Governments in these countries hold a substantial degree of subjective control over the application and enforcement of laws and the conduct of business. This inequality would become particularly detrimental if a business dispute arose between joint venture parties. Ivanhoe Mines seeks to minimize this issue by including international arbitration clauses in relevant agreements whenever possible and by maintaining positive relations with its joint venture partners and local governments, but there can be no guarantee that these measures will be sufficient to protect Ivanhoe Mines' interest in these countries.

Economic Sanctions

In May, 1997, the United States government imposed economic sanctions on Myanmar, banning new investments in Myanmar by any United States investor. In August, 1997, the Canadian government imposed selective economic sanctions on Myanmar, directed against imports and exports between Canada and Myanmar. These sanctions were based on the United States and Canadian governments' belief that the current government of Myanmar has repressed opposition to the government. While the sanctions in their current form do not affect the Company's investments in Myanmar, there can be no assurances that the sanctions will not be broadened or that other countries will not adopt sanctions in the future. The existence of United States sanctions may restrict the ability of United States companies to participate in the Monywa Copper Project. It is not possible to assess whether additional legislation will be enacted by the United States, Canada, the European Union or elsewhere or, if enacted, will ultimately affect the Company or investment in the Company.

Currency Risks

The bulk of the Company's activities are denominated in U.S. currency. During the past two years, the Company invested most of its surplus funds in cash instruments denominated in Canadian dollars. During most of that two-year period, the Canadian dollar strengthened against the U.S. dollar, resulting in a foreign exchange gain to the Company. There is no guarantee that the Canadian dollar will continue on this trend in the future and a sudden weakening of the Canadian dollar vis-a-vis the U.S. dollar could generate a significant foreign exchange loss to the Company.

Limited Production History

The Company has paid no dividends on its common shares since incorporation and does not anticipate doing so in the foreseeable future. To date, the Company has not received any cash flow generated by the S&K Mine. All other exploration and development projects of Ivanhoe Mines will need funding from the Company. Ivanhoe Mines has a limited operating history and there can be no assurance of its ability to operate its projects profitably. While Ivanhoe Mines may in the future generate additional working capital through the operation, development, sale or possible syndication of its properties, there is no assurance that Ivanhoe Mines will be capable of producing positive cash flow on a consistent basis or that any such funds will be available for exploration and development programs.

Uninsurable Risks or Self-insured Risks

Exploration, development and production operations on mineral properties involve numerous risks, including unexpected or unusual geological operating conditions, rock bursts or slides, fires, floods, earthquakes or other environmental occurrences, and political and social instability. It is not always possible to obtain insurance against all such risks and the Company may decide not to insure against certain risks as a result of high premiums or other reasons. Should such liabilities arise, they could reduce or eliminate any further profitability and result in increasing costs and a decline in the value of the securities of the Company. Ivanhoe Mines does not maintain insurance against political or environmental risks. Also, because of the recent major increases in insurance premiums and the inability to obtain full coverage, the S&K Mine is self-insuring on a portion of the mine assets.

Extent of Liability for Previous Environmental Damage

Ivanhoe Mines has received exemptions from liability from relevant governmental authorities for environmental damage caused by previous mining operations at the S&K Mine and the Bakyrchik Project. There is a risk, however, that, if an environmental accident occurred at those sites, it may be difficult or impossible to assess the extent to which environmental damage was caused by Ivanhoe Mines' activities or the activities of previous operators. In that event, the indemnities could be ineffective and possibly worthless.

Limited Customer Base

Substantially all of the Ivanhoe Mines' production from the S&K Mine is sold to a single Japanese buyer. If, for any reason, the S&K Mine was unable to continue to sell its production to its existing buyer, economic sanctions against trade with Myanmar may significantly reduce the number of potential alternative buyers.

RELATED-PARTY TRANSACTIONS

At the end of 2004 and 2003, the Company's discontinued operations owed approximately $5.1 million to Mr. Friedland. This debt originated as a result of the December 2000 acquisition, by the Company, of the Savage River operation. Following the sale of the Savage River operations in February 2005, repayment of this balance is contingent upon the Company receiving proceeds in excess of approximately $111 million from the sale of the Savage River operations.

The Company is a party to cost-sharing agreements with other companies in which Robert M. Friedland, its Chairman and Chief Executive Officer, has a material, direct or indirect, beneficial interest. Through these agreements, Ivanhoe Mines shares, on a cost-recovery basis, office space, furnishings, equipment and communications facilities in Vancouver, Singapore, Beijing and London, and an aircraft. Ivanhoe Mines also shares the costs of employing administrative and non-executive management personnel in these offices.

Companies in which the Company is a party to the cost-sharing agreement and Mr. Friedland's ownership interest in each of them, are as follows:

Company Name	R.M. Friedland's Ownership Interest (%)
Ivanhoe Energy Inc.	27.47
Ivanhoe Capital Corporation	100.00
Ivanhoe Nickel & Platinum Ltd.	50.06

The Company's related-party transactions also include transactions with Asia Gold Corp., (a 51.1%-owned subsidiary) and exploration expenditures incurred as part of several joint-venture agreements with Jinshan Gold Mines Inc.(a 38.5%-owned, publicly listed company).

The shared and other expenditures for the last two years were as follows:

Years ended December 31,	2004	2003
Exploration	$ 2,198	$ 1,768
Legal	468	—
Office and Administrative	2,057	1,834
Salaries and Benefits	2,239	1,372
Travel (including aircraft rental)	3,001	2,636
	9,963	7,610

Accounts receivable and accounts payable of the Company at December 31, 2004, included $0.4 million and $3.3 million, respectively (December 31, 2003 – $0.3 million and $0.3 million, respectively), which were due from/to a company under common control or companies related by way of directors in common.

OFF-BALANCE-SHEET ARRANGEMENTS

In 2004, the Company did not have any off-balance-sheet arrangements that have, or are reasonably likely to have, a current or future effect on the results of operations or financial condition of the Company, except for the call options discussed under "Financial Instruments" below.

FINANCIAL INSTRUMENTS

In September 2004, in order to obtain some protection against the weakening of the U.S. dollar, the management of the Savage River Mine negotiated a 12-month, $60 million call options program, providing the mine with the option to buy the AUD$ equivalent of $5 million each month at $0.7298 in 2004 and $0.7150 in 2005.

Conversely for the same 12-month period, the mine is obliged each month to buy the AUD$ equivalent of $5 million at $0.7298 in 2004 and $0.7150 in 2005 if the AUD$ value at the end of any month is below $0.7030 in 2004 and $0.6866 in 2005.

At December 31, 2004, these financial instruments were marked to market by the Savage River mine operations, which resulted in an unrealized foreign exchange gain of approximately $3 million being included in the net income from discontinued operations in 2004.

QUALIFIED PERSONS

Disclosure of a scientific or technical nature in this MD&A in respect of the Oyu Tolgoi Project was prepared under the supervision of Charles P.N. Forster, an employee of Ivanhoe Mines and a qualified person under National Instrument 43-101. Disclosure of a scientific or technical nature in this MD&A in respect of the Monywa Copper Project was prepared by or under the supervision of Mark Haywood, an employee of Ivanhoe Mines and a qualified person under National Instrument 43-101.

OVERSIGHT ROLE OF THE AUDIT COMMITTEE

The Audit Committee reviews, with management and the external auditors, the Company's quarterly MD&A and related consolidated financial statements and approves the release of such information to shareholders. For each audit or quarterly review, the external auditors prepare a report for members of the Audit Committee summarizing key areas, significant issues and material internal control weaknesses encountered, if any.

MANAGEMENT'S REPORT TO THE SHAREHOLDERS

The Consolidated Financial Statements and the management's discussion and analysis of financial condition and results of operations ("MD&A") are the responsibility of the management of Ivanhoe Mines Ltd. These financial statements and the MD&A have been prepared in accordance with accounting principles generally accepted in Canada and regulatory requirements, respectively, using management's best estimates and judgment of all information available up to March 21, 2005.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit Committee of the Board of Directors, consisting solely of outside directors, meets regularly during the year with financial officers of the Company and the external auditors to satisfy itself that management is properly discharging its financial reporting responsibilities to the Directors who approve the consolidated financial statements.

These financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the accounting policies summarized in Note 2 to the Consolidated Financial Statements.

The consolidated financial statements have been audited by Deloitte & Touche LLP, the independent registered chartered accountants, in accordance with Canadian generally accepted auditing standards. They have full and unrestricted access to the Audit Committee.

R. M. Friedland
CHAIRMAN
March 21, 2005
Vancouver, BC Canada

P. Meredith
CHIEF FINANCIAL OFFICER

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Shareholders of Ivanhoe Mines Ltd.

We have audited the consolidated balance sheets of Ivanhoe Mines Ltd. as at December 31, 2004 and 2003 and the consolidated statements of operations, shareholders' equity and cash flows for each of the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and 2003 and the results of its operations, changes in its shareholders' equity and its cash flows for each of the years then ended in accordance with Canadian generally accepted accounting principles.

The Company is not required to have, nor were we engaged to perform, an audit of its internal controls over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no opinion.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Vancouver, British Columbia
March 10, 2005

COMMENT BY INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS ON CANADA-UNITED STATES OF AMERICA REPORTING DIFFERENCE

In the United States of America, the reporting standards of the Public Company Accounting Oversight Board (United States) for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when the financial statements are affected by matters such as that described in Note 26 (a) to the consolidated financial statements. Our report to the shareholders dated March 10, 2005 is expressed in accordance with Canadian reporting standards which do not permit a reference to such matters in the auditors' report when they are adequately disclosed in the financial statements.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Vancouver, British Columbia
March 10, 2005

Consolidated Balance Sheets

(Stated in thousands of U.S. dollars)

December 31,	2004	2003
ASSETS		
Current		
Cash *(Note 5)*	$ 122,577	$ 106,994
Investments *(Note 6)*	—	50,000
Accounts receivable *(Note 7)*	10,286	4,440
Broken ore on leach pads	9,394	6,181
Inventories *(Note 8)*	5,516	2,571
Prepaid expenses	2,996	1,639
Other current assets	3,117	2,107
Current assets held for sale *(Note 3)*	34,918	23,127
	188,804	197,059
Long-term investments *(Note 9)*	16,281	14,716
Mining property, plant and equipment *(Note 10)*	132,599	129,188
Other mineral property interests *(Note 11)*	50,316	49,796
Other capital assets *(Note 12)*	8,909	7,990
Future income taxes *(Note 16)*	782	1,781
Other assets *(Note 13)*	7,472	7,135
Non-current assets held for sale *(Note 3)*	55,711	48,057
	$ 460,874	$ 455,722
LIABILITIES		
Current		
Accounts payable and accrued liabilities *(Note 14)*	$ 24,764	$ 38,938
Current portion of asset retirement obligations *(Note 17 (b))*	—	388
Current portion of long-term debt *(Note 15)*	7,500	15,000
Current liabilities held for sale *(Note 3)*	14,082	14,635
	46,346	68,961
Future income taxes *(Note 16)*	12,788	13,092
Other liabilities *(Note 17)*	11,040	10,188
Non-controlling interest *(Note 18)*	3,713	5,816
Non-current liabilities held for sale *(Note 3)*	31,468	22,418
	105,355	120,475
SHAREHOLDERS' EQUITY		
Share capital *(Note 19)*		
Authorized		
Unlimited number of preferred shares without par value		
Unlimited number of common shares without par value		
Issued and outstanding		
292,870,998 (2003 – 265,440,052) common shares	873,536	719,289
Special warrants	—	49,975
Additional paid-in capital	210	404
Contributed surplus	11,863	6,044
Deficit	(530,090)	(440,465)
	355,519	335,247
	$ 460,874	$ 455,722

Commitments *(Note 24)*

Approved by the board:

J. Weatherall, Director

K. Thygesen, Director

Consolidated Statements of Operations

(Stated in thousands of U.S. dollars, except per share amounts)

Years ended December 31,		2004		2003
Revenue	$	44,091	$	22,866
Cost of operations		(11,412)		(12,428)
Depreciation and depletion		(5,177)		(5,484)
Operating profit		27,502		4,954
EXPENSES				
General and administrative		(22,825)		(17,393)
Interest on long-term debt		(1,105)		(1,444)
Exploration *(Note 9 (a))*		(98,174)		(67,989)
Depreciation		(2,027)		(1,501)
Loss before the following		(96,629)		(83,373)
OTHER INCOME (EXPENSES)				
Interest income		3,177		1,613
Foreign exchange gains		4,442		12,376
Mining property care and maintenance costs *(Note 10)*		(3,755)		(3,356)
Share of loss of significantly influenced investees *(Note 9 (a) and (b))*		(2,315)		(2,423)
Gain on sale of long-term investments *(Note 9 (c) and (e))*		4,523		4,625
Write-down of carrying values of other assets *(Note 20)*		(5,277)		(1,213)
Dilution gain on investment in subsidiary		—		4,210
Dilution loss on long-term investment in significantly influenced investee		—		(237)
Other		(183)		685
		612		16,280
Loss before income and capital taxes, non-controlling interest and discontinued operations		(96,017)		(67,093)
Provision for income and capital taxes *(Note 16)*		(4,350)		(1,756)
Loss before non-controlling interest and discontinued operations		(100,367)		(68,849)
Non-controlling interest *(Note 18)*		2,103		546
Net loss from continuing operations		(98,264)		(68,303)
Net income (loss) from discontinued operations *(Note 3)*		8,639		(4,685)
Net loss	$	(89,625)	$	(72,988)
BASIC AND DILUTED EARNINGS (LOSS) PER SHARE FROM:				
Continuing operations	$	(0.35)	$	(0.28)
Discontinued operations		0.03		(0.02)
	$	(0.32)	$	(0.30)
Weighted average number of shares outstanding *(000's)*		281,640		243,814

Consolidated Statements of Shareholders' Equity

(Stated in thousands of U.S. dollars)

	Share Capital						
	Number of Shares	Amount	Special Warrants	Additional Paid-In Capital	Contributed Surplus	Deficit	Total
Balances, December 31, 2002	205,163,382	$ 522,199	$ 26,516	$ 1,508	$ 3,520	$ (367,477)	$ 186,266
Special Warrants issued	—	—	109,234	—	—	—	109,234
Shares issued for:							
Private placements	14,300,000	105,475	—	—	—	—	105,475
Exercise of special warrants	41,296,080	85,775	(85,775)	—	—	—	—
Exercise of stock options	4,407,815	5,158	—	(1,104)	(1,156)	—	2,898
Share purchase plan	49,745	113	—	—	—	—	113
Bonus shares	125,000	263	—	—	—	—	263
Consulting fees	98,030	306	—	—	—	—	306
Stock compensation charged to operations	—	—	—	—	3,680	—	3,680
Net loss	—	—	—	—	—	(72,988)	(72,988)
Balances, December 31, 2003	265,440,052	$ 719,289	$ 49,975	$ 404	$ 6,044	$ (440,465)	$ 335,247
Shares issued for:							
Private placements	20,000,000	100,593	—	—	—	—	100,593
Exercise of special warrants	5,760,000	49,975	(49,975)	—	—	—	—
Exercise of stock options	1,502,554	2,233	—	(194)	(698)	—	1,341
Exercise of share purchase warrants	25,000	244	—	—	—	—	244
Share purchase plan	17,019	102	—	—	—	—	102
Consulting fees	126,373	1,100	—	—	—	—	1,100
Stock compensation charged to operations	—	—	—	—	6,517	—	6,517
Net loss	—	—	—	—	—	(89,625)	(89,625)
Balances, December 31, 2004	292,870,998	$ 873,536	$ —	$ 210	$ 11,863	$ (530,090)	$ 355,519

Consolidated Statements of Cash Flows

(Stated in thousands of U.S. dollars)

Years ended December 31,	2004	2003
OPERATING ACTIVITIES OF CONTINUING OPERATIONS		
Net loss from continuing operations	$ (98,264)	$ (68,303)
Items not involving use of cash		
Depreciation and depletion	7,204	6,985
Expenditures on deferred stripping costs	(238)	(486)
Amortization of deferred stripping costs	105	—
Non-cash stock based compensation	6,517	3,680
Non-cash interest expense	519	241
Non-cash exploration expense recovery *(Note 9 (a))*	(3,248)	—
Unrealized foreign exchange gains	(5,444)	(13,717)
Share of loss of significantly influenced investees	2,315	2,423
Gain on sale of long-term investments	(4,523)	(4,625)
Write-down of carrying values of other assets	5,277	1,213
Dilution gain on investment in subsidiary	—	(4,210)
Dilution loss on long-term investment in significantly influenced investee	—	237
Future income taxes	695	688
Non-controlling interest	(2,103)	(546)
(Decrease) increase in non-current portion of royalty payable	(756)	461
Other	339	—
Net change in non-cash operating working capital items *(Note 22 (a))*	(7,584)	4,731
	(99,189)	(71,228)
INVESTING ACTIVITIES OF CONTINUING OPERATIONS		
Redemption (purchase) of investments	50,000	(50,000)
Purchase of long-term investments	(3,846)	(3,923)
Proceeds from sale of long-term investments	2,461	6,709
Proceeds from sale of other mineral property interests	460	—
Proceeds from sale of other capital assets	2,260	—
Change in restricted cash	—	2,000
Expenditures on mining property, plant and equipment	(8,160)	(1,927)
Expenditures on other mineral property interests	(20,773)	(26,067)
Expenditures on other capital assets	(5,410)	(6,034)
Expenditures on other assets	(60)	(2,887)
Other	(6,249)	1,570
	10,683	(80,559)
FINANCING ACTIVITIES OF CONTINUING OPERATIONS		
Issue of share capital and special warrants	102,280	218,026
Non-controlling interests' investment in subsidiary	—	10,572
Repayment of long-term debt	(7,500)	(7,500)
	94,780	221,098
Effect of exchange rate changes on cash from continuing operations	5,369	13,810
Net cash inflow from continuing operations	11,643	83,121
Net cash inflow (outflow) from discontinued operations *(Note 3)*	3,940	(8,819)
Net increase in cash	15,583	74,302
Cash, beginning of year	106,994	32,692
Cash, end of year	$ 122,577	$ 106,994
Cash is comprised of:		
Cash on hand and demand deposits	$ 33,796	$ 32,450
Short-term money market instruments	88,781	74,544
	$ 122,577	$ 106,994

Supplementary information *(Note 22 (b) and (c))*

1. NATURE OF OPERATIONS

Ivanhoe Mines Ltd. (the "Company"), together with its subsidiaries and joint venture (collectively referred to as "Ivanhoe Mines"), is an international mineral exploration and development company holding interests in and conducting operations on mineral resource properties principally in Southeast and Central Asia and Australia.

2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). In the case of the Company, Canadian GAAP differs in certain respects from accounting principles generally accepted in the United States ("U.S. GAAP") as explained in Note 26. The significant accounting policies used in these consolidated financial statements are as follows:

(a) Principles of consolidation

These consolidated financial statements include the accounts of the Company and all of its subsidiaries. The principal subsidiaries of the Company are ABM Mining Limited (Yukon, Canada), Ivanhoe Mines Mongolia Inc. (B.V.I.), Ivanhoe Myanmar Holdings Limited (Myanmar), Asia Gold Corp. (B.C., Canada) (51% owned) and their respective subsidiaries, and Bakyrchik Mining Venture (Kazakhstan) (70% owned). ABM Mining Limited and its subsidiaries are individually and collectively referred to in these financial statements as "ABM".

Ivanhoe Mines' investment in Myanmar Ivanhoe Copper Company Limited ("JVCo") (Myanmar) (50% owned), which is subject to joint control, is consolidated on a proportionate basis whereby the Company includes in these consolidated financial statements its proportionate share of the assets, liabilities, revenues and expenses of JVCo.

All intercompany transactions and balances have been eliminated, where appropriate.

(b) Accounting estimates

Generally accepted accounting principles require management to make assumptions and estimates that affect the reported amounts and other disclosures in these consolidated financial statements. Actual results may differ from those estimates.

Significant estimates used in the preparation of these consolidated financial statements include, amongst other things, the recoverability of accounts receivable and investments, the quantities of copper on leach pads and in circuit, the proven and probable ore reserves, the estimated tonnes of waste material to be mined and the estimated recoverable tonnes of ore from each mine area, the estimated net realizable value of inventories, the provision for income taxes and the composition of future income tax assets and future income tax liabilities, the expected economic lives of and the estimated future operating results and net cash flows from mining property, plant and equipment, and the anticipated costs of asset retirement obligations including the reclamation of mine sites.

(c) Foreign currencies

The Company considers the U.S. dollar to be its functional currency as it is the currency of the primary economic environment in which the Company and its subsidiaries operate. Accordingly, monetary assets and liabilities denominated in foreign currencies are translated into U.S. dollars at the exchange rate in effect at the balance sheet date and non-monetary assets and liabilities at the exchange rates in effect at the time of acquisition or issue. Revenues and expenses are translated at rates approximating the exchange rates in effect at the time of the transactions. All exchange gains and losses are included in operations.

(d) Cash

Cash includes short-term money market instruments with terms to maturity, at the date of acquisition, not exceeding ninety days.

(e) Investments

Investments are recorded at the lower of cost and market value.

(f) Broken ore on leach pads

The broken ore on leach pads comprises copper in process on heap leach pads that is valued at the lower of the weighted average cost of production and net realizable value. All of this ore has been classified as a current asset since, based on historical leaching data, the copper is expected to be recovered within the next twelve months. The units of copper on the leach pads are estimated based on the amount of ore placed on the pads, the expected recovery rates and actual production.

Ivanhoe Mines reviews the estimated units of copper on the heap leach pads on a regular basis and, where appropriate, revises its estimates of those quantities to recognize changes in the expected recovery rates based on actual experience.

(g) Inventories

Metals inventories are valued at the lower of the weighted average cost of production and net realizable value.

Mine stores and supplies are valued at the lower of the weighted average cost, less allowances for obsolescence, and replacement cost.

(h) Long-term investments

Long-term investments in companies in which Ivanhoe Mines has a 20% to 50% voting interest, or where Ivanhoe Mines has the ability to exercise significant influence, are accounted for using the equity method. Under this method, Ivanhoe Mines' share of their earnings and losses is included in operations and its investments therein are adjusted by a like amount. Dividends received are credited to the investment accounts.

The other long-term investments are accounted for using the cost method, whereby income is included in operations when received or receivable.

Ivanhoe Mines reviews the carrying value of each investment whenever events or changes in circumstances indicate that its carrying value may exceed its estimated net recoverable amount. An impairment loss is recognized when the carrying value of the investment exceeds its fair value.

(i) Mining property, plant and equipment and other capital assets

Mining property, plant and equipment and other capital assets are carried at cost (including development and preproduction costs, capitalized interest, other financing costs and all direct administrative support costs incurred during the construction period, net of cost recoveries and incidental revenues) less accumulated depletion and depreciation including write-downs. Following the construction period, interest, other financing costs and administrative costs are expensed as incurred.

On the commencement of commercial production, depletion of each mining property is provided on the unit-of-production basis using estimated proven and probable reserves as the depletion basis. The mining plant and equipment and other capital assets are depreciated, following the commencement of commercial production, over their expected economic lives using either the unit-of-production method or the straight-line method (over two to fifteen years), as appropriate.

Capital projects in progress are not depreciated until the capital asset has been put into operation.

Ivanhoe Mines reviews the carrying values of its mining property, plant and equipment and other capital assets whenever events or changes in circumstances indicate that their carrying values may exceed their estimated net recoverable amounts determined by reference to estimated future operating results and undiscounted net cash flows. An impairment loss is recognized when the carrying value of those assets is not recoverable and exceeds their fair value.

(j) Other mineral property interests

All direct costs related to the acquisition of other mineral property interests are capitalized. Exploration costs are charged to operations in the period incurred until such time as it has been determined that a property has economically recoverable reserves, in which case subsequent exploration costs and the costs incurred to develop a property are capitalized. Exploration costs include value-added taxes incurred in foreign jurisdictions when recoverability of those taxes is uncertain.

Ivanhoe Mines reviews the carrying values of its other mineral property interests whenever events or changes in circumstances indicate that their carrying values may exceed their estimated net recoverable amounts. An impairment loss is recognized when the carrying value of those assets is not recoverable and exceeds their fair value.

Certain of Ivanhoe Mines' exploration activities are conducted jointly with others. These consolidated financial statements reflect only Ivanhoe Mines' interests in such activities.

(k) Stripping costs

Mining costs associated with waste rock removal are deferred or accrued, as appropriate, and charged to operations on the basis of the estimated average stripping ratio for each mine area. The average stripping ratio is calculated as the ratio of the tonnes of waste material estimated to be mined to the estimated recoverable tonnes of metals from that mine area.

(l) Asset retirement obligations

Ivanhoe Mines recognizes liabilities for statutory, contractual or legal obligations associated with the retirement of mining property, plant and equipment, when those obligations result from the acquisition, construction, development or normal operation of the assets. Initially, a liability for an asset retirement obligation is recognized at its fair value in the period in which it is incurred. Upon initial recognition of the liability, the corresponding asset retirement cost is added to the carrying amount of that asset and the cost is amortized as an expense over the economic life of the related asset. Following the initial recognition of the asset retirement obligation, the carrying amount of the liability is increased for the passage of time and adjusted for changes to the amount or timing of the underlying cash flows needed to settle the obligation.

(m) Revenue recognition

Revenue from the sale of metals is recognized, net of related royalties and sales commissions, when: (i) persuasive evidence of an arrangement exists; (ii) the risks and rewards of ownership pass to the purchaser including delivery of the product; (iii) the selling price is fixed or determinable, and (iv) collectibility is reasonably assured.

(n) Stock-based compensation

The Company has an Employees' and Directors' Equity Incentive Plan which is disclosed in Note 19. The Company accounts for its grants under that Plan using the fair value based method of accounting for stock-based compensation. Accordingly, the fair value of stock options at the date of grant is amortized to operations, with an offsetting credit to contributed surplus, on a straight-line basis over the vesting period. In situations where Ivanhoe Mines grants stock options in connection with a business acquisition, the fair value of the options at the date of grant is included in the cost of the acquisition, with an offsetting credit to additional paid-in capital. If and when the stock options are ultimately exercised, the applicable amounts of additional paid-in capital and contributed surplus are transferred to share capital.

(o) Commodity and foreign exchange contracts

Ivanhoe Mines uses, from time to time, forward currency contracts that are not designated as a hedge. These contracts are marked-to-market at each balance sheet date and the unrealized gains and losses on these contracts, included in Other Assets and Other Liabilities, respectively, in the Consolidated Balance Sheets, are also included in operations.

(p) Income taxes

Future income tax assets and liabilities are computed based on differences between the carrying amounts of assets and liabilities on the balance sheet and their corresponding tax values, using the enacted or substantially enacted, as applicable, income tax rates at each balance sheet date. Future income tax assets also result from unused loss carry-forwards and other available deductions. The valuation of future income tax assets is reviewed quarterly and adjusted, if necessary, by use of a valuation allowance to reflect the estimated realizable amount.

(q) Loss per share

The basic loss per share is computed by dividing the net loss by the weighted average number of common shares and Special Warrants outstanding during the year. The diluted loss per share reflects the potential dilution of common share equivalents, such as outstanding stock options and share purchase warrants, in the weighted average number of common shares outstanding during the year, if dilutive. For this purpose, the "treasury stock method" is used for the assumed proceeds upon the exercise of outstanding stock options and share purchase warrants that are used to purchase common shares at the average market price during the year. For the years ended December 31, 2004 and 2003, all of the outstanding stock options and share purchase warrants were anti-dilutive.

(r) Comparative figures

Certain of the comparative figures have been reclassified to conform with the presentation as at and for the year ended December 31, 2004. In particular, the assets and liabilities of ABM as at December 31, 2003, and its results of operations and cash flows for the year then ended (Note 3) have been classified as held for sale and discontinued operations, respectively.

3. ASSETS HELD FOR SALE

In November 2004, the Company adopted a plan to dispose of the Savage River Iron Ore Project (the "Project"). This decision is part of the Company's plan to rationalize its non-core assets as it focuses on the Oyu Tolgoi project in Mongolia. In February 2005, Ivanhoe Mines sold the Project for two initial payments totalling $21.5 million, plus a series of contingent, escalating-scale annual payments based on annual iron ore pellet sales of 1.8 million tonnes and an escalating price formula based on the prevailing annual Nibrasco/JSM pellet price.

Ivanhoe Mines received the first initial payment of $15.0 million on February 28, 2005 and the second payment of $6.5 million is due on July 31, 2005. The escalating payments will be made over five years commencing March 2006. The escalating payments will be calculated at an initial rate of $1.00 per tonne of iron ore pellets if the annual benchmark pellet price exceeds $30 per tonne, and will escalate to a maximum of $16.50 per tonne of iron ore pellets if the annual price exceeds $80 per tonne. At December 31, 2004, the prevailing annual Nibrasco/JSM price was $38.10 per tonne which is expected to increase by 71.5% effective March 31, 2005.

Ivanhoe Mines expects to recover the carrying value of the net assets held for sale through expected future cash flows arising from the sale of the Project, and any excess will be included in operations if, as and when realized.

The following tables present summarized financial information related to discontinued operations:

Years ended December 31,		2004		2003
Revenue	$	83,898	$	66,833
Cost of operations		(71,614)		(63,480)
Depreciation and depletion		(4,369)		(5,305)
Operating profit		7,915		(1,952)
EXPENSES				
General and administrative		(416)		(103)
Interest on long-term debt		(1,021)		(991)
Income (loss) before the following		6,478		(3,046)
Interest income		308		211
Other income (expense)		(1,009)		308
Foreign exchange gain (loss)		3,745		(1,907)
Income (loss) before income taxes		9,522		(4,434)
(Provision for) recovery of income taxes		(883)		(251)
Net income (loss) from discontinued operations	$	8,639	$	(4,685)
Net cash provided by (used in) operating activities	$	3,150	$	(3,631)
Net cash used in investing activities		(4,657)		(3,629)
Net cash provided by (used in) financing activities		5,431		(1,853)
Effect of exchange rate changes on cash flows from discontinued operations		16		294
Net cash inflow (outflow) from discontinued operations	$	3,940	$	(8,819)

December 31,		2004		2003
ASSETS				
Current				
Cash	$	7,432	$	1,183
Accounts receivable		3,985		2,350
Inventories		19,577		18,718
Prepaid expenses		882		876
Other current assets		3,042		—
Current assets held for sale		34,918		23,127
Mining property, plant and equipment		25,581		25,734
Other assets (includes deferred stripping costs)		30,130		22,323
Non-current assets held for sale		55,711		48,057
Total assets held for sale	$	90,629	$	71,184
LIABILITIES				
Current				
Accounts payable and accrued liabilities	$	13,870	$	14,334
Current portion of long-term debt		212		301
Current liabilities held for sale		14,082		14,635
Loans payable to related parties		5,088		5,088
Long-term debt (non-recourse to the Company)		13,025		6,878
Future income taxes		2,078		1,217
Other liabilities		11,277		9,235
Non-current liabilities held for sale		31,468		22,418
Total liabilities held for sale	$	45,550	$	37,053
Net assets held for sale	$	45,079	$	34,131

Subsequent to December 31, 2004, Ivanhoe Mines continuing operations assumed the loans payable to related parties. Repayment of these loans has been postponed until Ivanhoe Mines receives an aggregate of $111,000,000 from the sale of the Project.

4. JOINT VENTURE

Ivanhoe Mines has a 50% interest in JVCo, a joint venture formed to develop open-pit copper mining operations at Monywa in the Union of Myanmar. JVCo has a term, with respect to each deposit, of twenty years from the date of commercial production, which is renewable in certain circumstances for an additional five years.

JVCo completed construction of a mining complex in 1998 to develop the Sabetaung and Kyisintaung ("S&K") deposits within the Monywa Copper Project. Commercial production from those deposits commenced during the first quarter of 1999.

These consolidated financial statements include Ivanhoe Mines' proportionate share of JVCo's assets, liabilities, revenues, expenses, retained earnings, net income and cash flows as follows:

December 31,	2004	2003
Current assets	$ 28,352	$ 11,608
Mining property, plant and equipment[1]	130,869	129,121
Future income tax assets	464	371
Other assets	3,700	3,543
Current liabilities	(16,329)	(20,120)
Future income tax liabilities	(11,429)	(10,888)
Other liabilities	(5,774)	(5,868)
Retained earnings	(35,664)	(13,522)
Investment in JVCo eliminated on consolidation	$ 94,189	$ 94,245

Years ended December 31,	2004	2003
Revenues	$ 44,091	$ 22,865
Expenses	(21,949)	(20,756)
Net income	$ 22,142	$ 2,109
Cash flows		
From operating activities	$ 25,325	$ 6,881
For investing activities	(9,086)	(1,777)
For financing activities	(7,500)	(7,500)
	$ 8,739	$ (2,396)

[1]Ivanhoe Mines investment in JVCo exceeds it proportionate share of the net assets of JVCo by $71,796,000, which is included in mining property, plant and equipment.

5. CASH

Cash at December 31, 2004 and 2003 included Ivanhoe Mines' share of JVCo's cash balances of approximately $10,099,000 and $1,478,000, which were not available for Ivanhoe Mines' general corporate purposes.

6. INVESTMENTS

In December 2003, Ivanhoe Mines purchased a $50.0 million one-year treasury bill, bearing interest at 3% per annum, from the Government of Mongolia. This treasury bill, including interest of $1.3 million, was fully repaid during 2004.

7. ACCOUNTS RECEIVABLE

December 31,	2004	2003
Trade	$ 4,239	$ 1,093
Refundable taxes	4,576	2,192
Accrued interest	134	56
Other	1,337	1,099
Allowance for doubtful accounts	—	—
	$ 10,286	$ 4,440

8. INVENTORIES

December 31,	2004	2003
Metals		
Finished goods	$ 588	$ 418
Work in progress	120	124
Mine stores, supplies and other	4,808	2,029
	$ 5,516	$ 2,571

9. LONG-TERM INVESTMENTS

	December 31, 2004			December 31, 2003		
	Equity Interest (%)	Carrying Value	Quoted Market Value	Equity Interest (%)	Carrying Value	Quoted Market Value
Investment in companies subject to significant influence:						
Jinshan Gold Mines Inc. (formerly Pacific Minerals Inc.) ("Jinshan") *(a)*	38.5	$ 5,024	$ 10,267	35.5	$ 9,027	$ 39,712
Portfolio investments:						
Intec Ltd. ("Intec") *(b)*	12.8	1,446	2,915	23.2	1,787	4,479
Olympus Pacific Minerals Inc. ("Olympus") *(c)*	19.6	5,862	5,569	10.8	2,587	3,342
Entrée Gold Inc. ("Entrée") *(d)*	9.0	3,846	5,550	—	—	—
Resource Investment Trust ("RIT") *(e)*	—	—	—	6.2	1,212	2,237
Other	—	103	—	—	103	—
		$ 16,281	$ 24,301		$ 14,716	$ 49,770

(a) In 2003, the Company acquired 2.5 million units of Jinshan at a price of Canadian ("Cdn") $1.75 per unit, for a cost of Cdn$4.4 million ($3.3 million). Each unit consisted of one common share and one common share purchase warrant. Each warrant is exercisable for one common share at a price of Cdn$2.20 per share until December 2005.

In 2004, Ivanhoe Mines and Jinshan restructured their participating arrangements in respect of certain joint ventures. In consideration for the transaction, Jinshan issued to Ivanhoe Mines 2.5 million common shares with a fair value of $3,248,000. This amount has been included in operations as a recovery of prior exploration expenses.

During 2004, Ivanhoe Mines recorded a $1,974,000 (2003 – $2,333,000) equity loss on this investment, and an impairment provision of $5,277,000 (2003 – Nil) based on an assessment of the underlying book value of Jinshan's net assets. At December 31, 2004, the carrying value of the Company's investment in Jinshan exceeded its share of the underlying book value of Jinshan's net assets by approximately $2,709,000, which is being accounted for against the Company's share of Jinshan's post-acquisition net income or losses in accordance with the accounting policy described in Note 2(i).

At December 31, 2004, Ivanhoe Mines' equity interest in Jinshan on a fully diluted basis, which assumes that all of the outstanding share purchase warrants and stock options of Jinshan were exercised, amounts to 45.0%. At March 10, 2005, the quoted market value of the Company's investment in Jinshan was $11,327,000.

(b) In 2003, Ivanhoe Mines acquired additional shares of Intec for cash of $493,000. This acquisition increased Ivanhoe Mines' holding in Intec from 19.9% to 23.2% and, accordingly, Ivanhoe Mines commenced equity accounting for its investment in Intec. In the fourth quarter of 2004, Ivanhoe Mines' interest in Intec was decreased to 12.8% as a result of the issuance of additional shares by Intec. As a result, Ivanhoe Mines ceased equity accounting for its investment in Intec. During 2004, Ivanhoe Mines recorded a $341,000 (2003 – $90,000) equity loss on this investment.

(c) During 2004, the Company sold its 32.6% interest in New Vietnam Mining Corp. (BVI) ("NVM"), in exchange for shares of Olympus Pacific Minerals, representing a 10.7% equity interest, with a fair value of $3,275,000. The interest in NVM had been fully written down in prior years, thereby resulting in a pre-tax gain of $3,275,000 being recognized in operations.

(d) During 2004, the Company purchased 4.6 million units of Entrée at a cost of Cdn$4.6 million ($3.8 million). Each unit consisted of one Entrée common share and one purchase warrant exercisable until October 2006 to purchase an additional Entrée common share at a price of Cdn$1.10.

(e) During 2004, the Company sold its entire investment in Resource Investment Trust, generating proceeds of $2,460,000. This transaction resulted in a pre-tax gain of $1,248,000 being recognized in operations.

10. MINING PROPERTY, PLANT AND EQUIPMENT

	2004			2003
December 31,	Cost	Accumulated Depletion and Depreciation, Including Write-downs	Net Book Value	Net Book Value
Mining properties, including development and preproduction costs	$ 137,434	$ (46,979)	$ 90,455	$ 91,586
Mine buildings	2,405	(816)	1,589	1,706
Plant and equipment	59,888	(19,333)	40,555	35,896
	$ 199,727	$ (67,128)	$ 132,599	$ 129,188

Mining property, plant and equipment comprises the Monywa Copper Project (Note 4) and the Bakyrchik Mining Venture ("BMV").

Ivanhoe Mines placed the BMV on a care and maintenance basis in prior years. This project, which had an original cost, including asset retirement obligations, of $94 million and $92 million as at December 31, 2004 and 2003, respectively, is carried at $1,730,000 and $67,000, respectively.

Capital projects in progress amounted to $15,000 at December 31, 2004 and $450,000 at December 31, 2003.

11. OTHER MINERAL PROPERTY INTERESTS

December 31,	2004	2003
Mongolia:		
Oyu Tolgoi *(a)*	$ 42,999	$ 42,997
Other *(b)*	159	159
Australia *(c)*	5,722	6,210
Inner Mongolia, China *(d)*	1,436	255
South Korea *(e)*	—	175
	$ 50,316	$ 49,796

The foregoing table reflects the application of Ivanhoe Mines' accounting policy discussed in Note 2 (j).

(a) Mongolia: Oyu Tolgoi – Ivanhoe Mines has a 100% interest in the Turquoise Hill (Oyu Tolgoi) copper/gold project in Mongolia.

In November 2003, Ivanhoe Mines entered into an agreement with BHP Minerals International Exploration Inc. ("BHP") to purchase for $37 million BHP's 2% net smelter return royalty interest in the Turquoise Hill project. Ivanhoe Mines paid BHP $17 million in November 2003 and the remaining $20 million, included in accounts payable and accrued liabilities at December 31, 2003, was paid in February 2004.

In December 2003, Ivanhoe Mines converted its 4 exploration licences on the Turquoise Hill project into 60 year mining licences, which are renewable for an additional 40 years.

(b) Mongolia: Other – Ivanhoe Mines has also acquired interests in additional mineral exploration licenses in the same geological province as the Turquoise Hill project and elsewhere in Mongolia. Mineral exploration licenses are valid for a period of three years and, through renewals, can be extended to a maximum of seven years. These rights are maintained in good standing through the payment of an annual license fee.

(c) Australia – In 2003, Ivanhoe Mines purchased certain copper-gold mining and exploration leases in Queensland, Australia.

(d) Inner Mongolia, China – Ivanhoe Mines has entered into an agreement with a Chinese government agency which contemplates the negotiation of definitive joint venture agreements whereby Ivanhoe Mines would conduct exploration activities in order to earn an 80% interest in certain properties.

In 2004, Ivanhoe Mines purchased a small-scale mining property located in Inner Mongolia for a cost of $1.2 million.

Ivanhoe Mines has also entered into a joint venture agreement which provides that Ivanhoe Mines can earn an 80% interest in a joint venture by contributing $2.8 million over a three-year period, with a minimum contribution of $250,000. The agreement is subject to Chinese government approval. The joint venture has also agreed, subject to due diligence, Chinese government approvals and certain other conditions, to purchase the leasehold rights to a small scale mine and related assets for approximately $1.6 million.

(e) South Korea – In July 2004, Ivanhoe Mines sold its 90% interest in an exploration project in the Cholla-namdo Province of South Korea.

12. OTHER CAPITAL ASSETS

	2004			2003
December 31,	Cost	Accumulated Depreciation	Net Book Value	Net Book Value
Other mining plant and equipment	$ 9,117	$ (1,858)	$ 7,259	$ 6,760
Furniture and fixtures	2,571	(921)	1,650	1,230
	$ 11,688	$ (2,779)	$ 8,909	$ 7,990

The other mining plant and equipment are used primarily in Ivanhoe Mines' other mineral property interest projects in Mongolia, Australia, Myanmar and Inner Mongolia, China.

13. OTHER ASSETS

December 31,		2004		2003
Due from JVCo	$	1,569	$	1,532
Advances to suppliers		917		891
Environmental bond (Queensland, Australia)		2,847		2,704
Deferred stripping costs		2,139		2,008
	$	7,472	$	7,135

The amount due from JVCo is unsecured with no fixed terms of repayment and bears interest at LIBOR plus 2%. Ivanhoe Mines charged interest of $65,000 in 2004 and $50,000 in 2003, which is included in the balance receivable.

14. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

December 31,		2004		2003
Trade	$	7,349	$	6,357
Amounts payable on acquisition of other mineral property interests *(Note 11 (a))*		—		20,000
Payroll and other employee related payables		3,754		4,250
Amounts payable to related parties *(Note 21 (b))*		3,285		333
Accrued income taxes		3,981		667
Other accrued liabilities		6,395		7,331
	$	24,764	$	38,938

15. LONG-TERM DEBT

JVCo's loan of $15,000,000 (of which $7,500,000 is Ivanhoe Mines' proportionate share) at December 31, 2004 bears interest at a rate equal to LIBOR plus 2.5%, subject to certain adjustments, and is repayable in minimum semi-annual installments of $7,500,000 (of which $3,750,000 is attributable to Ivanhoe Mines) until maturity in August 2005. The loan facility is secured by, amongst other things, a fixed charge on the Monywa Copper Mine Project assets, an assignment of JVCo's operating and restricted cash balances, and a floating charge on all other assets of JVCo. This debt is non-recourse to the Company.

JVCo is required to pay a non-refundable management fee of 0.75% per annum on the amounts drawn-down. This amount is included in interest on long-term debt. The effective interest rate on the loan facility was 5.23% at December 31, 2004 and 4.47% at December 31, 2003. Ivanhoe Mines' share of the interest incurred on this loan during the year ended December 31, 2004 and 2003 amounted to $563,000 and $979,000, respectively.

16. INCOME TAXES

As referred to in Note 2(b), Ivanhoe Mines must make significant estimates in respect of the provision for income taxes and the composition of its future income tax assets and future income tax liabilities. Ivanhoe Mines' operations are, in part, subject to foreign tax laws where interpretations, regulations and legislation are complex and continually changing. As a result, there are usually some tax matters in question which may, on resolution in the future, result in adjustments to the amount of future income tax assets and future income tax liabilities, and those adjustments may be material to Ivanhoe Mines' financial position and results of operations.

Ivanhoe Mines' provision for income and capital taxes for continuing operations consists of the following:

Years ended December 31,		2004		2003
Current income taxes	$	3,102	$	667
Future income taxes		695		692
Capital taxes		553		397
	$	4,350	$	1,756

Future income tax assets and liabilities for continuing operations at December 31, 2004 and 2003 arise from the following:

December 31,		2004		2003
Future income tax assets				
Long-term investments	$	2,441	$	1,711
Loss carry-forwards		86,691		58,756
Other		11,442		10,115
		100,574		70,582
Valuation allowance		(99,792)		(68,801)
Net future income tax assets		782		1,781
Future income tax liabilities				
Mining property, plant and equipment		12,188		12,300
Other		600		792
		12,788		13,092
Future income tax liabilities, net	$	12,006	$	11,311

A reconciliation of the provision for income and capital taxes for continuing operations is as follows:

Years ended December 31,		2004		2003
Provision for recovery of income taxes based on the combined Canadian federal and provincial statutory tax rates of 35.6% in 2004 and 37.6% in 2003 applied to the loss before income and capital taxes and non-controlling interest	$	34,182	$	25,227
Add (deduct)				
Lower foreign tax rates		(585)		(5,046)
Tax benefit of losses not recognized		(36,026)		(19,747)
Change in valuation allowance for future income tax assets		842		(409)
Capital taxes		(553)		(397)
Other, including non-deductible expenses		(2,210)		(1,384)
Provision for income and capital taxes	$	(4,350)	$	(1,756)

At December 31, 2004, Ivanhoe Mines had deductible temporary differences aggregating approximately $26,399,000 and the following unused tax losses from continuing operations, for which no future income tax assets had been recognized:

In Thousands		Local Currency		U.S. Dollar Equivalent[1]	Expiry Dates
Non-capital losses:					
Canada (Cdn.)	$	72,224	$	60,092	2005 to 2011
Australia (A)	$	8,261	$	6,435	*(a)*
Mongolia (Mongolian Tugrik)		211,983,688	$	174,544	*(b)*
Kazakhstan (Kazakhstan Tenge)		11,201,570	$	86,192	2005 to 2011
Capital losses:					
Canada (Cdn.)	$	67,457	$	56,125	*(c)*

[1] Translated using the year-end exchange rate.

(a) These losses are carried forward indefinitely, subject to continuity of ownership and business tests.
(b) These losses are carried forward indefinitely until such time as production from a mine commences; thereafter, they can be amortized on a straight-line basis over a period of five years.
(c) These losses are carried forward indefinitely for utilization against any future net realized capital gains.

Ivanhoe Mines also has deductible temporary differences and unused tax losses in certain other foreign jurisdictions that are not disclosed above, as it is currently highly unlikely that these items will be utilized.

17. OTHER LIABILITIES

December 31,		2004		2003
Royalty payable *(a)*	$	1,404	$	2,160
Asset retirement obligations *(b)*		9,636		8,028
	$	11,040	$	10,188

(a) Royalty payable

JVCo is required to pay a royalty to the Ministry of Mines of the Union of Myanmar on the value of Copper Cathode sold. However, during the first five years following the commencement of sales of Copper Cathode, payment of one-half of the royalty was deferred and is payable in equal installments over the next five years. Ivanhoe Mines' share of the amount of the royalty payable due within one year is included in accounts payable and accrued liabilities and the balance is payable as to $432,000 in each of 2006 though 2008 and $108,000 in 2009.

(b) Asset retirement obligations

December 31,		2004		2003
Balance, beginning of year	$	8,416	$	5,817
Increase in obligations for:				
Amounts incurred		1,089		444
Amounts arising on acquisition of mineral property interests		—		1,731
Amounts extinguished on disposal of mineral property interests		(388)		—
Accretion expense		519		424
Balance, end of year		9,636		8,416
Less: Amount included in current liabilities		—		(388)
	$	9,636	$	8,028

The total undiscounted amount of estimated cash flows required to settle the obligations is $17,426,000 (2003 – $14,427,000), which has been discounted using credit adjusted risk free rates ranging from 5.6% to 8.4%. All reclamation obligations are not expected to be paid for several years in the future and will be funded from Ivanhoe Mines' cash balances at the time of mine closures.

18. NON-CONTROLLING INTEREST

At December 31, 2004 and 2003, there were non-controlling interests in the Bakyrchik Mining Venture ("BMV") and Asia Gold Corp. ("AGC"). Currently, losses applicable to the non-controlling interest in the BMV are being allocated to Ivanhoe Mines since those losses exceed the non-controlling interest in the net assets of the BMV.

The non-controlling interest in AGC is comprised of the following:

Initial interest arising from initial public offering completed by AGC in 2003	$	6,362
Non-controlling interests' share of loss of AGC		(546)
Balance, December 31, 2003	$	5,816
Non-controlling interests' share of loss of AGC		(2,103)
Balance, December 31, 2004	$	3,713

19. SHARE CAPITAL

(a) Equity Incentive Plan

The Company has an Employees' and Directors' Equity Incentive Plan (the "Equity Incentive Plan"), which includes three components: (i) a Share Option Plan; (ii) a Share Bonus Plan; and (iii) a Share Purchase Plan.

(i) The Share Option Plan authorizes the Board of Directors of the Company to grant options, which vest over a period of years, to directors and employees of Ivanhoe Mines to acquire Common Shares of the Company at a price based on the weighted average trading price of the Common Shares for the five days preceding the date of the grant. The Share Option Plan also provides that these options may, upon approval of the Board of Directors, be converted into stock appreciation rights.

(ii) The Share Bonus Plan permits the Board of Directors of the Company to authorize the issuance, from time to time, of Common Shares of the Company to employees of the Company and its affiliates.

(iii) The Share Purchase Plan entitles each eligible employee of Ivanhoe Mines to contribute a percentage of his or her annual basic salary in semi-monthly installments. Each participant is, at the end of each calendar quarter during which he or she participates in the Share Purchase Plan, issued Common Shares of the Company equal to 1.5 times the aggregate amount contributed by the participant, based on the weighted average trading price of the Common Shares during the preceding three months.

The Company is authorized to issue a maximum of 20,000,000 Common Shares pursuant to the Equity Incentive Plan. At December 31, 2004, an aggregate of 104,734 Common Shares are available for future grants of awards under the plan.

A summary of share option activity and information concerning outstanding and exercisable options at December 31, 2004 is as follows:

	Options Outstanding		
	Options Available for Grant	Number of Common Shares	Weighted Average Exercise Price[1]
Balances, December 31, 2002	4,547,384	12,309,094	1.64
Options granted	(1,730,000)	1,730,000	9.30
Options exercised	—	(4,780,683)	1.38
Options cancelled	670,517	(670,517)	2.46
Shares issued for bonus shares	(125,000)	—	—
Shares issued for consulting fees	(98,030)	—	—
Shares issued under share purchase plan	(49,745)	—	—
Balances, December 31, 2003	3,215,126	8,587,894	3.26
Options granted	(3,089,000)	3,089,000	7.91
Options exercised	—	(1,665,952)	1.58
Options cancelled	122,000	(122,000)	2.93
Shares issued for consulting fees	(126,373)	—	—
Shares issued under share purchase plan	(17,019)	—	—
Balances, December 31, 2004	104,734	9,888,942	$ 5.02

[1] Expressed in Canadian dollars

At December 31, 2004, the U.S. dollar equivalent of the weighted average exercise price was $4.18.

The following table summarizes information concerning outstanding and exercisable options at December 31, 2004:

Options Outstanding			Options Exercisable	
Number Outstanding	Weighted Average Remaining Contractual Life (in years)	Weighted Average Exercise Price Per Share[1]	Number Exercisable	Weighted Average Exercise Price Per Share[1]
2,884,442	1.09	$ 1.20	2,174,119	$ 1.20
600,000	1.73	1.60	400,000	1.60
33,750	1.25	1.61	18,000	1.61
30,000	1.07	1.70	30,000	1.70
10,000	3.36	2.12	10,000	2.12
325,000	1.07	2.15	—	2.15
120,250	1.88	2.31	90,250	2.31
80,000	2.10	3.05	60,000	3.05
1,173,500	2.83	3.25	565,800	3.25
245,000	3.51	3.50	205,000	3.50
20,000	2.76	6.74	20,000	6.74
280,000	3.71	6.75	112,000	6.75
150,000	4.68	7.00	—	7.00
309,000	4.83	7.27	61,800	7.27
100,000	3.00	7.36	—	7.36
573,000	4.10	7.69	114,600	7.69
1,000,000	9.25	7.78	200,000	7.78
430,000	4.37	8.20	86,000	8.20
400,000	4.44	8.81	—	8.81
50,000	4.99	8.99	10,000	8.99
75,000	4.04	10.00	15,000	10.00
1,000,000	8.84	12.70	500,000	12.70
9,888,942	3.79	$ 5.02	4,672,569	$ 3.72

[1] Expressed in Canadian dollars

The weighted average grant-date fair value of stock options granted during 2004 and 2003 was Cdn$4.77 and Cdn$6.78, respectively. The fair values of these options were determined using a Black-Scholes option pricing model, recognizing forfeitures as they occur, using the following weighted average assumptions:

	2004	2003
Risk-free interest rate *(%)*	4.29	4.71
Expected life *(years)*	6.6	7.8
Expected volatility *(%)*	64	65
Expected dividends	$ Nil	$ Nil

(b) Share Purchase Warrants

At December 31, 2004, the Company had share purchase warrants outstanding as follows:

Number of Warrants	Total Number of Shares to be Issued	Exercise Price (Per Share)	Maturity Date
5,760,000 (issued in 2004)	576,000	$8.68	Feb. 15, 2005[1]
7,125,000 (issued in 2003)	7,125,000	Cdn$12.50	Dec. 19, 2005

[1] In January 2005, the maturity date of these warrants was extended to February 15, 2006.

20. WRITE-DOWN OF CARRYING VALUES OF OTHER ASSETS

Years ended December 31,	2004	2003
Long-term investments – Jinshan *(Note 9 (a))*	$ 5,277	$ —
South Korea mineral property interests and other capital assets	—	1,213
	$ 5,277	$ 1,213

21. OTHER RELATED-PARTY TRANSACTIONS

(a) Ivanhoe Mines incurred the following expenses, primarily on a cost recovery basis, with an officer of Ivanhoe Mines, a company subject to significant influence by Ivanhoe Mines, or with companies related by way of directors or shareholders in common:

Years ended December 31,	2004	2003
Exploration	$ 2,198	$ 1,768
Legal	468	—
Office and administrative	2,057	1,834
Salaries and benefits	2,239	1,372
Travel (including aircraft rental)	3,001	2,636
	$ 9,963	$ 7,610

(b) Accounts receivable and accounts payable at December 31, 2004 included $414,000 and $3,285,000, respectively, (December 31, 2003 – $347,000 and $333,000, respectively) which were due from/to a company under common control or companies related by way of directors in common.

22. CASH FLOW INFORMATION

(a) Net change in non-cash operating working capital items

Years ended December 31,	2004	2003
(Increase) decrease in:		
Accounts receivable	$ (6,023)	$ (2,793)
Broken ore on leach pads	(3,213)	243
Inventories	(3,193)	(622)
Prepaid expenses	(1,431)	(985)
Other current assets	(1,010)	4,134
Increase in:		
Accounts payable and accrued liabilities	7,286	4,754
	$ (7,584)	$ 4,731

(b) Supplementary information regarding other non-cash transactions

The non-cash investing and financing activities relating to continuing operations not already disclosed in the Consolidated Statement of Shareholders' Equity or the Consolidated Statements of Cash Flows were as follows:

Years ended December 31,	2004	2003
INVESTING ACTIVITIES:		
Acquisition of other mineral property interest	$ —	$ (20,000)
Expenditures on other mineral property interests	—	(2,085)
FINANCING ACTIVITIES:		
Amount payable on acquisition of other mineral property interest	—	20,000
Asset retirement obligations	—	2,085

(c) Other supplementary information

Years ended December 31,	2004	2003
Interest paid	$ 552	$ 1,382
Income taxes paid	$ 342	$ 398

23. SEGMENT DISCLOSURES

Ivanhoe Mines has two operating segments, its copper division located in Myanmar, and its exploration division with projects located primarily in Mongolia. The iron ore division located in Australia has been reported as discontinued operations (Note 3). Capital assets consist of mining property, plant and equipment, other mineral property interests and other capital assets.

	Operating Segments			
Year ended December 31, 2004	Copper Division	Exploration Division	Corporate	Consolidated
Revenue	$ 44,091	$ —	$ —	$ 44,091
Cost of operations	(11,412)	—	—	(11,412)
Depreciation and depletion	(5,177)	—	—	(5,177)
Operating profit	27,502	—	—	27,502
Expenses				
General and administrative	(668)	—	(22,157)	(22,825)
Interest on long-term debt	(796)	(134)	(175)	(1,105)
Exploration	—	(98,174)	—	(98,174)
Depreciation	—	(2,002)	(25)	(2,027)
Income (loss) before the following	26,038	(100,310)	(22,357)	(96,629)
Other income (expenses)				
Interest income	51	232	2,894	3,177
Foreign exchange gains (losses)	(189)	48	4,583	4,442
Mining property care and maintenance costs	—	—	(3,755)	(3,755)
Share of loss of significantly influenced investees	—	—	(2,315)	(2,315)
Gain on sale of long-term investments	—	—	4,523	4,523
Write-down of carrying value of other assets	—	—	(5,277)	(5,277)
Other	4	366	(553)	(183)
Income (loss) before income and capital taxes, non-controlling interest and discontinued operations	25,904	(99,664)	(22,257)	(96,017)
Provision for income and capital taxes	(3,762)	(184)	(404)	(4,350)
Income (loss) before non-controlling interest and discontinued operations	22,142	(99,848)	(22,661)	(100,367)
Non-controlling interest	—	2,103	—	2,103
Net income (loss) from continuing operations	$ 22,142	$ (97,745)	$ (22,661)	$ (98,264)
Expenditures on capital assets	$ 6,859	$ 6,039	$ 1,445	$ 14,343
Expenditures on deferred stripping costs	$ 238	$ —	$ —	$ 238
Total assets				
Continuing operations	$ 161,940	$ 90,763	$ 117,542	$ 370,245
Held for sale	—	—	90,629	90,629
	$ 161,940	$ 90,763	$ 208,171	$ 460,874

	Operating Segments			
Year ended December 31, 2003	Copper Division	Exploration Division	Corporate	Consolidated
Revenue	$ 22,866	$ —	$ —	$ 22,866
Cost of operations	(12,428)	—	—	(12,428)
Depreciation and depletion	(5,484)	—	—	(5,484)
Operating profit	4,954	—	—	4,954
Expenses				
General and administrative	(683)	—	(16,710)	(17,393)
Interest on long-term debt	(1,224)	(57)	(163)	(1,444)
Exploration	—	(67,989)	—	(67,989)
Depreciation	—	(1,481)	(20)	(1,501)
Income (loss) before the following	3,047	(69,527)	(16,893)	(83,373)
Other income (expenses)				
Interest income	11	49	1,553	1,613
Foreign exchange gains (losses)	(264)	990	11,650	12,376
Mining property care and maintenance costs	—	—	(3,356)	(3,356)
Share of loss of significantly influenced investees	—	—	(2,423)	(2,423)
Gain on sale of long-term investments	—	—	4,625	4,625
Write-down of carrying value of other assets	—	(1,213)	—	(1,213)
Dilution gain on investment in subsidiary	—	4,210	—	4,210
Dilution loss on long-term investment in significantly influenced investees	—	—	(237)	(237)
Other	6	230	449	685
Income (loss) before income and capital taxes, non-controlling interest and discontinued operations	2,800	(65,261)	(4,632)	(67,093)
Provision for income and capital taxes	(691)	(159)	(906)	(1,756)
Income (loss) before non-controlling interest and discontinued operations	2,109	(65,420)	(5,538)	(68,849)
Non-controlling interest	—	546	—	546
Net income (loss) from continuing operations	$ 2,109	$ (64,874)	$ (5,538)	$ (68,303)
Expenditures on capital assets	$ 1,853	$ 8,527	$ 39,648	$ 50,028
Expenditures on deferred stripping costs	$ 486	$ —	$ —	$ 486
Total assets				
Continuing operations	$ 143,108	$ 85,703	$ 155,727	$ 384,538
Held for sale	—	—	71,184	71,184
	$ 143,108	$ 85,703	$ 226,911	$ 455,722

December 31,	2004	2003
Capital assets at the end of the year:		
Mongolia	$ 49,449	$ 46,584
Inner Mongolia, China	1,548	255
Myanmar	130,896	129,183
Australia	8,008	7,364
Kazakhstan	1,730	67
Canada	144	2,502
South Korea	—	806
Other	49	213
	$ 191,824	$ 186,974

During the years ended December 31, 2004 and 2003, substantially all of the revenue of the Copper Division arose from sales made to the major customer referred to in Note 24(a).

24. COMMITMENTS

(a) JVCo has entered into an agreement for the sale of a guaranteed quantity of Grade A Product (as defined in the agreement) from the Monywa Copper Mine Project to a company (the "Major Customer") affiliated with one of the lenders of the project financing. This agreement terminates no later than December 31, 2005, but may terminate earlier if certain events occur.

(b) Ivanhoe Mines has, in the normal course of its business, entered into various long-term contracts which include commitments for future operating payments under contracts for drilling, engineering, equipment rentals and other arrangements as follows:

2005	$	14,563
2006		349
2007		158
2008		55
	$	15,125

25. DISCLOSURES REGARDING FINANCIAL INSTRUMENTS

(a) The estimated fair value of Ivanhoe Mines' financial instruments was as follows:

	2004		2003	
December 31,	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash	$ 122,577	$ 122,577	$ 106,944	$ 106,944
Investments	—	—	50,000	50,000
Accounts receivable	10,286	10,286	4,440	4,440
Other current assets	3,117	3,117	2,107	2,107
Current assets held for sale *(Note 3)*	14,459	14,459	3,533	3,533
Long-term investments	16,281	24,301	14,716	49,770
Due from joint venture	1,569	1,569	1,532	1,532
Accounts payable	14,388	14,388	30,940	30,940
Current portion of long-term debt	7,500	7,500	15,000	15,000
Current liabilities held for sale *(Note 3)*	14,082	14,082	14,635	14,635
Royalty payable	1,404	—	2,160	—
Non-current liabilities held for sale *(Note 3)*	18,113	18,113	11,966	11,966

The fair value of Ivanhoe Mines' long-term investments was determined by reference to published market quotations which may not be reflective of future values.

Ivanhoe Mines' investments, amount due from the joint venture and long-term debt bear effective interest rates principally at current market rates and accordingly, their fair value approximates their carrying value.

The fair value of the royalty payable, by its nature, is not readily determinable.

The fair value of Ivanhoe Mines' remaining financial instruments was estimated to approximate their carrying value due primarily to the immediate or short-term maturity of these financial instruments.

(b) Ivanhoe Mines earns its revenues in U.S. dollars, but incurs certain of its expenses in currencies other than the U.S. dollar. As such, Ivanhoe Mines is subject to foreign exchange risk as a result of fluctuations in exchange rates.

(c) Ivanhoe Mines is exposed to credit risk with respect to its accounts receivable. The significant concentrations of credit risk are situated in Mongolia and Myanmar. Ivanhoe Mines does not mitigate the balance of this risk in light of the credit worthiness of its major debtors.

(d) The credit agreement discussed in Note 15 provides that JVCo shall, at the request of the lenders, from time to time maintain one or more swaps, caps, collars or similar hedge products commonly used to hedge against interest rate fluctuations, to protect itself against the LIBOR interest rate rising more than 2% per annum above that in effect on January 13, 1998 and as to a notional principal amount equal to 75% of the principal amount outstanding from time to time. JVCo will, however, be subject to interest rate cash flow risk on the remaining unhedged amount. JVCo currently has not entered into any such hedge products.

(e) Ivanhoe Mines is subject to market risk arising from revenues from the sale of metals, which are subject to price fluctuations beyond its control. Management of Ivanhoe Mines attempts to reduce its exposure to this market risk through the use of sale contracts designed to fix the sales prices of metals on a monthly or annual basis.

26. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

As indicated in Note 2, these consolidated financial statements have been prepared in accordance with Canadian GAAP, which, in the case of the Company, conforms in all material respects with U.S. GAAP, except as set forth below.

CONSOLIDATED STATEMENTS OF OPERATIONS (b)

(in thousands, except per share amounts)

Years ended December 31,		2004		2003[1]
Net (loss) from continuing operations in accordance with Canadian GAAP	$	(98,264)	$	(68,303)
Reclassification of dilution gain on investment in subsidiary to additional paid-in capital *(a)*		—		(4,210)
Amortization of deferred stock compensation *(c)*		—		(202)
Amortization of other mineral property interests *(e)*		—		(2,698)
Cumulative effect of accounting change *(f)*		—		(2,882)
Net (loss) from continuing operations in accordance with U.S. GAAP	$	(98,264)	$	(78,295)
Net income (loss) from discontinued operations in accordance with Canadian GAAP	$	8,639	$	(4,685)
Adjustment arising from write-down of the Savage River Project *(d)*		2,974		2,235
Cumulative effect of accounting change *(f)*		—		154
Net income (loss) from discontinued operations in accordance with U.S. GAAP	$	11,613	$	(2,296)
Net (loss) in accordance with U.S. GAAP	$	(86,651)	$	(80,591)
Weighted-average number of shares outstanding under U.S. GAAP (in thousands)		281,640		243,814
Basic and diluted income (loss) per share in accordance with U.S. GAAP from				
Continuing operations	$	(0.35)	$	(0.32)
Discontinued operations		0.04		(0.01)
	$	(0.31)	$	(0.33)
Proforma basic and diluted income (loss) per share, as if the accounting change had been applied retroactively				
Continuing operations	$	(0.35)	$	(0.31)
Discontinued operations		0.04		(0.01)
	$	(0.31)	$	(0.32)
Net (loss) under U.S. GAAP	$	(86,651)	$	(80,591)
Unrealized gain (loss) on portfolio investments, net of income taxes where applicable *(g)*		1,292		(2,350)
Comprehensive (loss) under U.S. GAAP *(h)*	$	(85,359)	$	(82,941)

[1] Restated – See *(a)*

CONSOLIDATED BALANCE SHEETS

December 31,		2004		2003
Total assets in accordance with Canadian GAAP	$	460,874	$	455,722
Reduction in fair value of the Savage River Project assets acquired *(c)*		(5,634)		(5,634)
Adjustment arising from write-down of the Savage River Project *(d)*		(24,759)		(27,733)
Amortization of other mineral property interests *(e)*		(6,521)		(6,521)
Adjustment to carrying value of long-term investments *(g)*		2,879		1,780
Total assets in accordance with U.S. GAAP	$	426,839	$	417,614
Total liabilities in accordance with Canadian GAAP	$	105,355	$	120,475
Income tax effect of U.S. GAAP adjustments for:				
Amortization of other mineral property interests *(e)*		(882)		(882)
Adjustment to carrying value of long-term investments *(g)*		—		193
Total liabilities in accordance with U.S. GAAP	$	104,473	$	119,786
Total shareholders' equity in accordance with Canadian GAAP	$	355,519	$	335,247
Reduction in fair value of shares issued to acquire ABM *(c)*		(4,930)		(4,930)
(Increase) decrease in the deficit for:				
Amortization of deferred stock compensation *(c)*		(704)		(704)
Adjustment arising from write-down of the Savage River Project *(d)*		(24,759)		(27,733)
Amortization of other mineral property interests *(e)*		(5,639)		(5,639)
Other comprehensive income *(h)*		2,879		1,587
Total shareholders' equity in accordance with U.S. GAAP	$	322,366	$	297,828

Under U.S. GAAP, the components of shareholders' equity would be as follows:

December 31,		2004		2003[1]
Share capital	$	868,608	$	714,359
Special warrants		—		49,975
Additional paid-in capital		16,281		10,658
Other comprehensive income		2,879		1,587
Deficit		(565,402)		(478,751)
	$	322,366	$	297,828

[1] Restated – See *(a)*

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended December 31,		2004		2003
Net cash used in operating activities of continuing operations in accordance with Canadian GAAP	$	(99,189)	$	(71,228)
Adjustments to net loss involving use of cash:				
Write off expenditures on other mineral interests *(e)*		—		(255)
Net cash used in operating activities of continuing operations in accordance with U.S. GAAP		(99,189)		(71,483)
Net cash from (used in) investing activities of continuing operations in accordance with Canadian GAAP		10,683		(80,559)
Reclassification of expenditures on mineral property interests *(e)*		—		255
Net cash from (used in) investing activities continuing operations in accordance with U.S. GAAP		10,683		(80,304)
Net cash flows from financing activities continuing operations in accordance with Canadian and U.S. GAAP		94,780		221,098
Effect of exchange rate changes on cash		5,369		13,810
Net cash inflow from continuing operations		11,643		83,121
Net cash inflow from discontinuing operations		3,940		(8,819)
Net increase in cash in accordance with Canadian and U.S. GAAP		15,583		74,302
Cash, beginning of year in accordance with Canadian and U.S. GAAP		106,994		32,692
Cash, end of year in accordance Canadian and U.S. GAAP	$	122,577	$	106,994

(a) Restatement

In 2004, Ivanhoe Mines concluded that, for U.S. GAAP purposes, the previously reported dilution gain on investment in a subsidiary that had been included in the results of operations for 2003, should have instead been accounted for as additional paid-in capital. Consequently, the net loss from continuing operations and the net loss under U.S. GAAP for the year ended December 31, 2003 have been increased by $4,210,000 ($0.02 per share) with no change in shareholders' equity under U.S. GAAP.

(b) Statements of operations

Under U.S. GAAP, the loss before other income (expenses) would include mining property care and maintenance costs and the write-down of carrying values of other assets.

(c) Acquisition of ABM

Under Canadian GAAP, the fair value of the shares issued in 2000 to effect the acquisition of ABM were measured at the transaction date whereas, under U.S. GAAP, the shares issued would have been measured at the date the acquisition was announced and the terms agreed to. This difference would have resulted in the cost of the acquisition under U.S. GAAP being $4,930,000 lower than under Canadian GAAP.

Under Canadian GAAP, the Company included in the cost of the acquisition of ABM $1,750,000 for the fair value of stock options granted by the Company in 2000 as consideration for the acquisition of all of the outstanding stock options of ABM. Under U.S. GAAP, the intrinsic value of the unvested options granted by the Company would have been allocated to deferred stock compensation included in shareholders' equity. This difference would have resulted in the cost of the acquisition in 2000 under U.S. GAAP being $704,000 lower than under Canadian GAAP. Under U.S. GAAP, the deferred stock compensation would have been recognized as a compensation cost over the remaining future vesting period of the options.

ABM was sold in February 2005 (Note 3).

(d) Impairment of long-lived assets

Under Canadian GAAP, impairment charges on long-lived assets in 2002 and prior years were recorded as the excess of their carrying amount over their recoverable amount, which was determined based on the undiscounted estimated future net cash flows, whereas, under U.S. GAAP, impairment charges are recorded based on the discounted estimated future net cash flows.

Under U.S. GAAP, the Savage River Project would have been fully written off as at December 31, 2002. In 2003, additional amounts capitalized under Canadian GAAP would also have been written off under U.S. GAAP. As a result, the related depreciation and depletion would have been reversed. The differences between Canadian and U.S. GAAP are as follows:

Year ended December 31,		2004		2003
Impairment of amounts capitalized under Canadian GAAP	$	—	$	(2,580)
Reversal of depreciation and depletion recorded under Canadian GAAP		2,974		4,815
	$	2,974	$	2,235

(e) Other mineral property interests

Under Canadian GAAP, the costs of acquisition of mineral property interests are capitalized.

Under U.S. GAAP, where the mineral property interests are, at the date of acquisition, without economically recoverable reserves, these costs are generally considered to be exploration costs which are expensed as incurred. However, the costs of acquisition of Ivanhoe Mines' mineral exploration licenses were classified at December 31, 2003 as intangible assets under U.S. GAAP and amortized over the term of the licenses. As a result, for U.S. GAAP purposes, Ivanhoe Mines recorded $2,698,000, net of deferred income taxes of $882,000, in amortization or write-offs of other mineral property interests for the year ended December 31, 2003.

During 2004, the Emerging Issues Task Force in the United States reached a consensus that mineral exploration licenses are tangible assets. This consensus was subsequently ratified by the United States Financial Accounting Standards Board ("FASB"). As a consequence, Ivanhoe Mines has changed its accounting policy for U.S. GAAP purposes, on a prospective basis from January 1, 2004, to reclassify the unamortized balance of these mineral exploration licenses, aggregating $41,306,000 at December 31, 2003, from intangible to tangible assets. As a result, there is no difference between Canadian and U.S. GAAP with respect to these unamortized costs.

For purposes of the Consolidated Statements of Cash Flows, the acquisition costs of mineral property interests that are written off for U.S. GAAP purposes are classified as cash used in operating activities rather than cash used in investing activities.

(f) Accounting change

Under Canadian GAAP, the accounting change made in 2003 with respect to asset retirement obligations was applied on a retroactive basis. Under U.S. GAAP, this accounting change would have been applied as of the beginning of 2003 and the cumulative effect of the initial application would have been accounted for as part of the result of operations for 2003.

(g) Long-term investments

Current investments are carried at the lower of cost and market value under Canadian GAAP. Under U.S. GAAP, these investments would be classified as held-to-maturity securities, which would also be carried at the lower of cost and market value.

Portfolio investments are carried at their original cost less provisions for impairment under Canadian GAAP. Under U.S. GAAP, these investments would be classified as available-for-sale securities, which are carried at market value. The resulting unrealized gains or losses would be included in the determination of comprehensive income, net of income taxes where applicable.

(h) Other comprehensive income

U.S. GAAP requires that a statement of comprehensive income be displayed with the same prominence as other financial statements and that the aggregate amount of comprehensive income excluding the deficit be disclosed separately in shareholders' equity. Comprehensive income, which incorporates the net loss, includes all changes in shareholders' equity during a period except those resulting from investments by and distributions to owners. There is currently no requirement to disclose comprehensive income under Canadian GAAP. However, the Company expects that this disclosure will be required by Canadian GAAP for fiscal years commencing on or after October 1, 2006.

(i) Income taxes

Under Canadian GAAP, future income taxes are calculated based on enacted or substantially enacted tax rates applicable to future years. Under U.S. GAAP, only enacted rates are used in the calculation of deferred income taxes. This difference in GAAP did not have any effect on the financial position or results of operations of the Company for the years ended December 31, 2004 and 2003.

(j) Joint venture

Under Canadian GAAP, the Company has accounted for its joint venture interest in JVCo (Note 4) on a proportionate consolidation basis. Under U.S. GAAP, interests in joint ventures are accounted for using the equity method. However, in accordance with practices prescribed by the United States Securities and Exchange Commission ("SEC") for foreign filing companies, if JVCo meets certain conditions, the Company is exempt from applying the equity method to its investment therein. JVCo satisfies the SEC conditions and, accordingly, there is no adjustment required for U.S. GAAP purposes.

(k) Recently released accounting standards

There are currently no recently released U.S. accounting standards requiring adoption by the Company subsequent to December 31, 2004 that are expected to have a material effect on its financial position or results of operations.

Ivanhoe's copper-gold and coal exploration and development projects in Mongolia

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

[X] Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. For the fiscal year ended December 31, 2004.

or

[ ] Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. For the transition period from ---------------------------- to ---------------------------- .

Commission file number 000-30586

IVANHOE ENERGY INC.

(Exact name of registrant as specified in its charter)

Yukon, Canada
(State or other jurisdiction of incorporation or organization)

98- 0372413
(I.R.S. Employer Identification No.)

654 — 999 Canada Place
Vancouver, British Columbia, Canada
V6C 3E1
(Address of principal executive offices)

(604) 688-8323
(Registrant's telephone number, including area code)

Securities to be registered pursuant to Section 12(b) of the Act: None

Securities registered or to be registered pursuant to Section 12(g) of the Act:

Title of each class	Name of each exchange on which registered
Common Shares, no par value	Toronto Stock Exchange NASDAQ SmallCap Market

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

Indicate by check mark whether the registrant is an accelerated filer as defined in Rule 12b-2 of the Act.

Yes [X] No [ ]

As at February 25, 2005, 169,892,413 common shares of the Registrant were issued and outstanding. The aggregate market value of the voting stock held by non-affiliates of the Registrant on June 30, 2004 based on the closing price on the NASDAQ SmallCap Market on that date, was $369,335,406.

Documents incorporated by reference: None

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CURRENCY AND EXCHANGE RATES

Unless otherwise specified, all reference to "**dollars**" or to "**$**" are to U.S. dollars and all references to "**Cdn.$**" are to Canadian dollars. The closing, low, high and average noon buying rates in New York for cable transfers for the conversion of Canadian dollars into U.S. dollars for each of the five years ended December 31 as reported by the Federal Reserve Bank of New York were as follows:

	2004	2003	2002	2001	2000
Closing	$ 0.83	$ 0.77	$ 0.63	$ 0.63	$ 0.67
Low	$ 0.72	$ 0.63	$ 0.62	$ 0.62	$ 0.64
High	$ 0.85	$ 0.77	$ 0.66	$ 0.67	$ 0.70
Average Noon	$ 0.77	$ 0.71	$ 0.63	$ 0.65	$ 0.67

The average noon rate of exchange reported by the Federal Reserve Bank of New York for conversion of U.S. dollars into Canadian dollars on February 25, 2005 was $ 0.81 ($1.00 = Cdn.$1.24).

ABBREVIATIONS

As generally used in the oil and gas business and in this Annual Report on Form 10-K, the following terms have the following meanings:

Boe	= barrel of oil equivalent
Bbl	= barrel
MBbl	= thousand barrels
MMBbl	= million barrels
Bopd	= barrels of oil per day
Bbls/d	= barrels per day
Boe/d	= barrels of oil equivalent per day
Mboe/d	= thousands of barrels of oil equivalent per day
MBbls/d	= thousand barrels per day
MMBls/d	= million barrels per day
MMBtu	= million British thermal units
Mcf	= thousand cubic feet
MMcf	= million cubic feet
Mcf/d	= thousand cubic feet per day
MMcf/d	= million cubic feet per day

When we refer to oil in "**equivalents**", we are doing so to compare quantities of oil with quantities of gas or to express these different commodities in a common unit. In calculating Bbl equivalents, we use a generally recognized industry standard in which one Bbl is equal to six Mcf. Boes may be misleading, particularly if used in isolation. The conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this document are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. Such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause our actual results, performance or achievements, or other future events, to be materially different from any future results, performance or achievements or other events expressly or implicitly predicted by such forward-looking statements. Such risks, uncertainties and other factors include, but are not limited to, our short history of limited revenue, losses and negative cash flow from our current exploration and development operations in the U.S. and China; our limited cash resources and consequent need for additional financing; our ability to raise additional financing; future benefits to be derived from the proposed acquisition of Ensyn Group, Inc. ("**Ensyn**"); conditions to completing the Ensyn acquisition and timetable for completion and other matters; uncertainties regarding the potential success of our oil and gas exploration and development properties in the U.S. and China; uncertainties regarding the potential success of heavy-to light oil upgrading and gas-to-liquids technologies; oil price volatility; oil and gas industry operational hazards and environmental concerns; government regulation and requirements for permits and licenses, particularly in the foreign jurisdictions in which we carry on business; title matters; risks associated with carrying on business in foreign jurisdictions; conflicts of interests; competition for a limited number of promising oil and gas exploration properties from larger more well financed oil and gas companies; and other statements contained herein regarding matters that are not historical facts. Forward-looking statements can often be identified by the use of forward-looking terminology such as "may", "will", "expect", "intend", "estimate", "anticipate", "believe" or "continue" or the negative thereof or variations thereon or similar terminology. We believe that any forward-looking statements made are reasonable based on information available to us on the date such statements were made. However, no assurance can be given as to future results, levels of activity and achievements. We undertake no obligation to update publicly or revise any forward-looking statements contained in this report. All subsequent forward-looking statements, whether written or oral, attributable to us, or persons acting on our behalf, are expressly qualified in their entirety by these cautionary statements.

ENFORCEABILITY OF CIVIL LIABILITIES

We were organized under the laws of Canada and our executive offices are located in British Columbia, Canada. Some of our directors, controlling persons and officers and representatives of the experts named in this Annual Report on Form 10-K reside outside the U.S. and a substantial portion of their assets and our assets are located outside the U.S. As a result, it may be difficult for you to effect service of process within the U.S. upon the directors, controlling persons, officers and representatives of experts who are not residents of the U.S. or to enforce against them judgments obtained in the courts of the U.S. based upon the civil liability provisions of the federal securities laws or other laws of the U.S. There is doubt as to the enforceability in Canada against us or against any of our directors, controlling persons, officers or experts who are not residents of the U.S., in original actions or in actions for enforcement of judgments of U.S. courts, of liabilities based solely upon civil liability provisions of the U.S. federal securities laws. Therefore, it may not be possible to enforce those actions against us, our directors, officers, controlling persons or experts named in this Annual Report on Form 10-K.

AVAILABLE INFORMATION

Copies of our annual reports on Form 10-K, our quarterly reports on Form 10-Q, our current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available free of charge on or through our website at or through the Securities and Exchange Commission's website at .

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

CORPORATE OVERVIEW

We are an international energy company engaged in the exploration for and production of oil and gas, enhanced oil recovery and natural gas projects and the application of heavy-to-light ("**HTL**") oil upgrading and gas-to-liquids ("**GTL**") technologies. Our core operations are in the United States and China, with business development opportunities worldwide.

We were incorporated pursuant to the laws of the Yukon, Canada, on February 21, 1995 under the name 888 China Holdings Limited. On June 3, 1996, we changed our name to Black Sea Energy Ltd., and on June 24, 1999, we changed our name to Ivanhoe Energy Inc.

Our authorized capital consists of an unlimited number of common shares without par value and an unlimited number of preferred shares without par value.

Our principal executive office is located at Suite 654 — 999 Canada Place, Vancouver, British Columbia, V6C 3E1, and our registered and records office is located at 300-204 Black Street, Whitehorse, Yukon, Y1A 2M9. Our headquarters for operations is located at Suite 400 – 5060 California Avenue, Bakersfield, California, 93309.

HISTORICAL OVERVIEW

We were incorporated in 1995 and, in 1996, established a series of joint ventures in Russia with local partners to enhance oil recovery from certain Russian oil and gas properties on which past field development practices had not maximized reserve recoveries. However, after successfully increasing oil production and reserves at the Kalchinskoye field in western Siberia, a dispute with our partner arose in 1998, which effectively prevented us from continuing to participate in the project. Although the dispute was settled in 2000, our management had already decided to terminate our business activities in Russia and implement a diversification program aimed at expanding the geographical scope of our business.

During 1998, we accumulated working interests and royalty interests in the San Joaquin Basin of California, primarily through an exploration agreement with Aera Energy LLC ("**Aera**"). This agreement entitled us to joint exploration rights with Aera in return for analyzing and identifying oil and gas prospects on properties owned by Aera in the San Joaquin Basin of southern California.

In June 1999, we expanded the geographical scope of our business by acquiring Sunwing Energy Ltd. ("**Sunwing**"), an oil and gas company with operations in China. As a result of our acquisition of Sunwing, we acquired two production-sharing contracts with China National Petroleum Corporation ("**CNPC**") to develop and operate the Kongnan oilfield in Dagang, located in Hebei Province and the Zhaozhou oilfield in Daqing located in Heilongjiang Province. We subsequently disposed of our interest in the Daqing field but retained a royalty. In April 2003, we received approval of our Overall Development Program ("**ODP**") for the Dagang field and in September 2003 we commenced drilling. We signed a farm-out agreement with China International Trust & Investment Corporation ("**CITIC**") for 40% of the Dagang field. This farm-out agreement provides that the parties will jointly develop the field, with Sunwing as the operator.

In April 2000, we acquired a limited volume license and, subsequently, a master license from Syntroleum Corporation ("**Syntroleum**") to use its proprietary GTL technology to convert natural gas into synthetic fuels. The master license allows us to use Syntroleum's proprietary process in an unlimited number of GTL projects throughout the world to convert natural gas into an unlimited volume of ultra clean transportation fuels and other synthetic petroleum products ("**Site License**"). We plan to use the technology in areas with large natural gas deposits, which would otherwise be uneconomic to develop. Our master license expires on the latter of April 2015 or five years from the effective date of the last Site License issued to us by Syntroleum.

During 2000 and 2001, we expanded into Texas by earning working interests in oil and gas exploration properties in the Spraberry Trend of the West Texas Permian Basin and leasing mineral rights in the East Texas Basin. In 2001, we entered into a joint venture agreement with a subsidiary of Unocal Corp. ("**Unocal**") to explore and develop prospects in the Bossier Trend of the East Texas Basin. We subsequently farmed-out our interests in three wells drilled by Unocal and currently have mineral rights in approximately 7,400 gross acres.

In February 2001, we extended our China interests. We entered into two memoranda of understanding with PetroChina Corporation ("**PetroChina**"), a subsidiary of CNPC, which gave us the exclusive right to negotiate production-sharing contracts for the development of oil and gas reserves in three blocks in the Sichuan Basin. In September 2002, we signed a 30-year production-sharing contract with CNPC for two of these blocks covering approximately 900,000 acres, which were combined into one Zitong block. In October 2003, we initiated the first phase of the exploration program in the Zitong block. We have the right to negotiate a production-sharing contract for the third block, the one-million-acre Yudong Block, located on the eastern edge of the Sichuan Basin.

In December 2002, we formed a wholly owned subsidiary, GTL Japan Corporation ("**GTLJ**") to facilitate the participation of Japanese companies in GTL projects and in November 2004 changed the name to Energy Resources Development Japan Corporation ("**ERDJ**") and expanded the charter of the company to include participation of multi-national companies in enhanced oil recovery ("**EOR**") projects, including those involving HTL oil upgrading.

In January 2004, we finalized an agreement with Derek Resources (USA), Inc. ("**Derek**") to jointly develop the LAK Ranch field, a steam assisted gravity drainage ("**SAGD**") project covering approximately 7,300 gross acres in the Powder River basin in Weston County, Wyoming.

In January 2004, we entered into a stock purchase and shareholders agreement with Ensyn and its subsidiary, Ensyn Petroleum International Limited ("**EPIL**") pursuant to which we acquired a 10% equity interest in EPIL for $2.0 million and certain rights to use their proprietary rapid thermal processing technology ("**RTP™ Technology**"). We subsequently increased our equity interest in EPIL to 15% in consideration of a cash payment to EPIL of $1.0 million.

In December 2004, we signed a definitive merger agreement to acquire Ensyn for $85 million. We agreed to pay $10 million in cash and to issue common shares valued at $75 million based on a weighted, 10-day average of our closing share price on the NASDAQ SmallCap Market determined prior to the closing of the acquisition (subject to a minimum issuance of 30 million shares), in exchange for all of the issued and outstanding shares of Ensyn common shares and the rights of holders of purchase warrants to acquire shares of Ensyn common shares that remain unexercised immediately after the effective time of the merger. We currently expect the merger with Ensyn to be completed early in the second quarter of 2005. Prior to the closing of the transaction, Ensyn will be required to satisfy our defined performance criteria for their California Commercial Demonstration Facility ("**CDF**").

In December 2004, we purchased the remaining working interest in seven wells, either producing or capable of producing, that we did not already own in the Knights Landing field in the Sacramento Gas Basin of northern California and an 80% working interest in four additional producing wells in which we did not previously hold an interest. The purchase includes mineral leases on 13,000 gross acres surrounding the producing wells. We originally farmed into this field in February 2004 for a 50% working interest after pay out.

CORPORATE STRATEGY

Our objective is to create shareholder value by finding and developing oil and gas reserves through the implementation of three main strategies: (1) conventional exploration and production ("**E&P**") of oil and gas, primarily in the U.S. and China, (2) EOR development projects, and (3) monetization of stranded oil and gas reserves through the application of the Ensyn RTP™ Technology and the technology licensed from Syntroleum. In pursuing these three business development areas, we are focused on achieving a balance in our short, medium and long-term goals. In the short term, we are focused on E&P and EOR projects that can be implemented and achieve early production and cash flow. Our medium term strategy is to continue exploration and development of our significant mineral interest holdings in California, Wyoming and China and develop opportunities for the Ensyn RTP ™ Technology in the oil sector. Our long-term priority is on GTL production of ultra clean fuels and specialty petroleum products. We have advanced each of these objectives during the past year and our projects continue to mature.

Our short-term objective is to focus on exploiting our existing mineral interest holdings and identifying new opportunities where

production can be achieved quickly and efficiently to create cash flow to fund our operations and allow us to pursue our medium and long-term objectives. To date, we have established oil and natural gas production in the South Midway and Citrus properties in the San Joaquin Basin, in the Knights Landing field in the Sacramento Gas Basin, in the Spraberry Trend of the West Texas Permian Basin and at the Dagang field in China. Over the next twelve months, we plan to drill more than thirty development wells on our current producing properties, six exploration wells in East Texas and non-Aera properties in California and also initiate a completion and testing program of our Northwest Lost Hills # 1-22 well, which is our deep gas play in the San Joaquin Basin.

One of the key elements of our medium-term strategy is continued exploration and development in the San Joaquin Basin. In 1998, we acquired exploration rights through an agreement with Aera, California's largest producer. This agreement gave us access to Aera's inventory of exploration, seismic and technical data for the purpose of identifying drillable prospects, primarily beneath or adjacent to existing oil fields in the San Joaquin Basin. Nine identified drillable prospects, in which Aera has agreed to participate, have yet to be explored. The LAK Ranch field is also a key element of our medium-term strategy. After completion of an ultra-high resolution 3-D seismic survey and interpretation in the first half of 2005, we plan to drill additional delineation wells to prove up oil-in-place reserves and commerciality of a full steam injection SAGD project.

Our exploration activities in China also have the potential to contribute to our medium-term growth. In September 2002, we entered into a 30-year production-sharing contract with CNPC in the western portion of the Sichuan Basin. Under the terms of the agreement, we will explore for and develop natural gas deposits on the 900,000-acre Zitong block. We plan to commence the drilling of our first exploration well on this block in the first quarter of 2005.

One of the most significant elements of our medium-term strategy is the acquisition of Ensyn. Current test results from over 90 test runs on heavy oil at Ensyn's pilot plant in Ontario show that Ensyn's RTP™ Technology offers a means of improving the value of heavy, sour crude oils in a manner that is comparable to established coking technologies but at significantly lower operating and capital costs. In addition, these test results evidence that the RTP™ Technology reduces or eliminates the need for an external energy source (usually natural gas, for steam production used in the recovery process), reduces the viscosity of the heavy oil and also permits the use of the processed oil to be used as a blending agent to facilitate the transportation of heavy oil by pipeline.

We believe that the innovative characteristics of Ensyn's RTP™ Technology offer the means to technologically and economically improve the production and marketing of heavy oil in the petroleum industry, which will provide us with an opportunity to significantly increase our base of oil reserves worldwide through joint venture and production sharing arrangements. As a result, the acquisition is expected to represent a major advance in the implementation of our corporate strategy because it will offer significant potential for broadening our access to project opportunities that might not otherwise be available to us.

Our long-term objective is to become a leader in the development and operation of GTL projects. We foresee rapidly increasing future demand for clean energy as environmental regulations become more stringent and the world's crude oil becomes more sour and heavy. We believe that Syntroleum's proprietary GTL technology holds significant potential for the economic production of synthetic fuels and other specialty petroleum products from stranded natural gas deposits throughout the world, which would otherwise be uneconomic to exploit. Although there are several competing GTL technologies under development, we believe that the Syntroleum technology offers several key advantages. Plant construction is less expensive and we believe the plant is safer to operate because, unlike competing technologies, the conversion process utilizes compressed air rather than pure oxygen.

OIL AND GAS PROPERTIES

Our primary oil and gas properties are located in California's San Joaquin Basin and Sacramento Gas Basin, the West Texas Permian and East Texas Basins, the Powder River Basin in Wyoming and the Hebei and Sichuan Provinces in China. Set forth below is a description of our material oil and gas properties.

California

Over the past seven years, we acquired interests in a number of properties in and around the San Joaquin Basin. In 2004, we acquired properties in the Knights Landing field in the Sacramento Gas Basin and established production in the Citrus field in the San Joaquin Basin. To date, our South Midway, Citrus and Knights Landing properties contain proved reserves and have wells on production. We cannot assure you that any of our other prospects in California will result in the development of commercially viable production.

Aera Exploration Agreement

The Aera exploration agreement, originally covering an area of more than 250,000 acres in the San Joaquin Basin, gave us access to all of Aera's exploration, seismic and technical data in the region for the purpose of identifying drillable exploration prospects. To date, we have identified 13 prospects within 11 areas of mutual interest ("**AMIs**") covering approximately 72,400 gross acres. Of the 13 prospects submitted, Aera has elected to take a working interest in 10 prospects, resulting in us retaining working interests ranging

from 12.5% to 50%. We have a 100% working interest in three prospects in which Aera elected not to participate. We will continue to hold exploration rights to the lands within previously designated and accepted prospect AMIs until an exploration well is drilled on that prospect. There is no time deadline for drilling to occur if Aera elects to participate in the drilling of a prospect. If Aera elects not to participate we have an additional two years to drill the prospect on our own or with other parties. This two-year period will be extended as long as we continue to drill or have established production.

- ***South Midway***

We currently have 55 producing wells in South Midway and are the operator, with a working interest of 100% and a 93% net revenue interest In 2004, we drilled seven new wells on the South Midway properties, consisting of six step-out development locations and one exploratory well. Four of the six development wells were completed as producers. The exploratory well was unsuccessful and will be held for a future disposal well.

In the southern expansion area, we have supplemented the cyclic steam project with a pilot to test continuous steam injection into two wells. The project began in October 2004 and by year-end 2004 it was beginning to yield increased production in the surrounding wells. If successful, continuous steam injection could increase recovery of the oil in place by an estimated 50-70%, similar to recovery in other fields in the area, and add a significant amount of probable reserves to our proved undeveloped reserves. Current production from the southern expansion area is approximately 165 Bopd and total South Midway production is approximately 585 Bopd.

- ***Citrus***

We are the operator of the Citrus field, located in the southern extension of the currently producing Lost Hills field, which is unrelated to our deep-gas prospect at Northwest Lost Hills, 15 miles to the north. We have leased mineral interests ranging from 83% to 100% in approximately 3,400 gross acres offsetting the Lost Hills field, where there has been development drilling.

One horizontal and two vertical development wells were drilled and completed on this southern extension area of the Lost Hills field in 2004. Production is currently approximately 120 Bopd and 450 Mcf/d of gas with all three wells on rod pump. We are evaluating drilling another horizontal leg on Citrus #1 by the second quarter of 2005. The target upper Antelope zone, located a few hundred feet above the existing horizontal well, should yield improved oil rates and reduced water from the lease. Development drilling may resume during the last half of 2005, following this test.

- ***Northwest Lost Hills***

The Northwest Lost Hills #1-22 well, operated by Aera, began drilling in August 2001. The well was designed to fully evaluate the natural gas and condensate reserve potential of the deep Temblor formation and reach a depth of approximately 20,000 feet. This drilling objective was achieved in August 2002 after substantial delays and cost overruns resulting from difficult drilling conditions. While drilling the well, we encountered several high-pressure intervals, which indicated the presence of natural gas, and decided to set casing in preparation for testing. In 2003, the well was temporarily abandoned pending the identification of one or more partners to share the costs of the testing program. Progress has been made towards finding investment partners to complete and test the Temblor formation and resolution of the Northwest Lost Hills #1-22 well is expected in 2005. Until it is tested, the well's commercial potential, if any, cannot be determined. Of the approximately 8,000 gross acres encompassing the Northwest Lost Hills prospect, we hold, on average, a 39% working interest. We have a 42% working interest in the Northwest Lost Hills #1-22 well. If, as and when we identify a partner to fund a test of the well's commercial potential, our working interest is expected to decrease by up to 50% under a new arrangement.

- ***Belgian Anticline***

We drilled the first well in this prospect in 2001 and found non-commercial gas shows. A second well in this prospect, originally contemplated for 2004, has been delayed and may be drilled in 2005. We have a 40% working interest in this prospect and Aera is the operator.

Other California Prospects

- ***Knights Landing***

In February 2004, we farmed into the Knights Landing field, which is a 13,000-acre block located in the Sutter and Yolo counties, in northern California. Under this exploration and development farm-in agreement, we purchased, for $1.0 million, a 50% working interest in four previous discoveries in the contract area and agreed to fund, for $0.6 million, gas gathering, surface treatment facilities and meters to connect the four wells to an existing pipeline system. We drilled nine new exploratory wells under this agreement in order to earn a 50% working interest after payout in any new discoveries. Our 2004 drilling resulted in three successful completions

and six dry holes. The three new discovery wells are expected to be connected in the first quarter of 2005. The primary objective of this development and exploration program is the Starkey Sand formation, which is an established producing reservoir in the region that lies between depths of 2,000 to 3,500 feet.

In December 2004, we reached an agreement with the operator of the field to purchase its interest, increasing our working interests in the field and existing producing gas wells to between 80% and 100%. We plan to use 3-D seismic to identify additional prospects and development well locations as well as reduce the dry hole risk in this gas producing area. Gross production is currently 1,520 Mcf/d from six producing wells. Well workovers are planned to increase gas rates and reduce operating costs.

- ***North South Forty***

In 1999, we entered into agreements with two other companies to pool certain of our acreage positions and jointly conduct a 3-D seismic survey in the southern San Joaquin Basin in order to identify new prospects. Although these agreements expired in 2003, we identified four drillable prospects covering approximately 13,400 gross acres, in which we have working interests ranging from 17.5% to 50%.

We participated with a 50% working interest in drilling two exploration prospects in the North South Forty area during 2004 but both wells were plugged and abandoned.

In December 2004, we participated in drilling a well with a carried 50% working interest in the third of the four prospects we developed from the 3-D seismic data in the North South Forty area. The Peach #1 well is located just west of the North Antelope Hills field. The well was drilled to a depth of 4,500 feet and initial evaluation was encouraging at test rates of 800Mcf/d on a 9/16-inch choke. During the test, the well produced natural gas and condensate with no water production. We will follow up testing with an estimate of commerciality, the drilling of an appraisal well and discussions with gas buyers. Gas gathering facilities and natural gas markets exist in close proximity to the discovery.

- ***Sledge Hamar***

In November 2003, we farmed into the Sledge Hamar prospect, which is located in a 900-acre block at the southern extension of the South Belridge field. The first well, Sledge Hamar 1-7, began producing in January 2004 at 30 Bopd from the Stevens sands at 4,950 feet. However, the follow up well drilled in April 2004 encountered the Stevens sands below the oil/water contact and tested only water. After evaluating the production results and other potential hydrocarbon intervals, we concluded that the future economic potential was unfavorable and, in December 2004, sold our working interest.

- ***McCloud Ranch / North Salt Creek***

In mid-2004, we farmed into the McCloud River Prospect near the Cymric field in the San Joaquin Basin with a 24% working interest. The initial well resulted in a dry hole. As a result of follow up work in the area, a second prospect was developed on the acreage called the North Salt Creek prospect. It is anticipated that we will participate with a 24% working interest and serve as operator for drilling this prospect in the first quarter of 2005. We have an interest in 1,140 gross acres over this prospect.

Texas

- ***Spraberry***

This producing property is located on 2,500 gross acres in the Spraberry Trend of the West Texas Permian Basin in Midland County, Texas, which we acquired in 2000 through a farm-in. After selling a portion of our working interests in 2002 for approximately $3 million, we retain working interests ranging from of 31% to 48% in 25 wells, which are currently producing approximately 80 net Boe/d.

- ***East Texas***

We currently own mineral rights in approximately 7,400 gross acres in East Texas but do not plan to renew leases as they expire except in the Creslenn Ranch, Catfish Creek and Malakoff prospects, which combined contain approximately 4,300 gross acres.

We spud the first well in the Malakoff prospect in the first quarter of 2005 where we will have a 25% carried working interest. The well is located in Henderson County, Texas and will be drilled to 8,200 feet to test the Rodessa and Travis Peak sands in the prospect. We have an interest in approximately 1,300 gross acres in the prospect.

In November 2003, we farmed out our interest in the Catfish Creek prospect for an 11,000-foot well to test the Rodessa and Pettit

formations. We will retain a 25% working interest after payout in this prospect and surrounding acreage. We plan to spud this well after drilling the first well in the Malakoff prospect.

In 2003, we farmed out our interests in two wells we drilled in the Creslenn Ranch prospect to test the shallower zones in the wells. A successful gas recompletion was made in the first well in July 2003 from the Pettit limestone and is currently on production. The second well was plugged and abandoned after determination was made that it was not economic. We retain a 30% working interest after payout in the producing well and a 50% working interest in the remaining acreage.

Wyoming

- ***LAK Ranch***

In January 2004, we signed farm-in and joint operating agreements with Derek for the joint development of the LAK Ranch field, a thermal recovery/horizontal well oil project in Weston County, Wyoming. The LAK Ranch field covers approximately 7,500 acres in Wyoming's Powder River basin.

Under the terms of the joint operating agreement, we will be the operator of the project and will earn an initial 30% working interest by financing the capital cost of the pilot phase. Following the pilot phase, we will have the option to increase our working interest to 60% by providing additional capital toward the initial development phase for a total of $5.0 million, including the amounts spent on the pilot phase. Thereafter, all future capital expenditures are to be shared on a working-interest basis. Should we elect not to proceed beyond the pilot phase our working interest will be reduced to 15% and Derek will become the operator.

Prior to the farm-in agreement, Derek completed a SAGD horizontal well pair to a depth of 1,000 feet and 1,800 feet into the Newcastle Sand formation. Surface steam-injection and oil-recovery equipment were installed. Extensive testing indicates that because of the viscosity of the oil, production can be expected to respond favorably to the application of continuous heat through steam injection. Facility modifications for the pilot phase were completed in the second quarter of 2004 to enable steam injection in the producing horizontal well. Two cycle steam stimulation treatments were performed during the year. The second cycle of steam injection was completed in September 2004 with over 13,000 barrels of steam injected into the horizontal well. Production following the second steaming increased from the first steam cycle. The well is currently producing minimal amounts of oil and may be stimulated with a third steam cycle in the first quarter of 2005, pending results of seismic interpretation and recent drilling data.

The ultra-high resolution 3-D seismic survey needed to better define the optimum reservoir development locations began in November and was completed in December 2004. We expect evaluation results during the second quarter of 2005. In addition, one vertical well was drilled in the first quarter of 2005 for data collection purposes. After completion of the 3-D seismic survey we plan to use the data to plan and drill injection wells and test the potential of continuous steam injection.

Following completion of the pilot phase, the development phase is scheduled to include additional horizontal production wells, new steam-injection and extension of surface facilities. We estimate that, at the low end of the initial development phase the program could grow to more than 20 producing wells. During the pilot phase, our working interest has increased from an initial 30% to 39% by year-end 2004. Should we decide to enter into the next two phases of the contract, our working interest will increase to a maximum of 60%. Should we elect not to proceed beyond the pilot phase, our working interest would be reduced to 15% and we would no longer be the operator.

China

- ***Dagang***

Our producing property in China is a 30-year production-sharing contract with CNPC, covering an area of 22,400 gross acres divided into six blocks in the Kongnan oilfield in Dagang, Hebei Province, China (the "**Dagang field**"). Under the contract as operator, we fund 100% of the development costs to earn 82% of the net revenue from oil production until cost recovery, at which time our entitlement reverts to 49%. In January 2004, we negotiated farm-out and joint operating agreements with Richfirst Holdings Limited ("**Richfirst**"), a wholly owned subsidiary of CITIC whereby Richfirst paid $20.0 million to acquire a 40% working interest in the field after Chinese regulatory approvals, which were finalized in June 2004. Richfirst will have the right to exchange its working interest in the Dagang field for common shares in Sunwing, should we obtain a public listing for Sunwing, or for common shares in Ivanhoe. Richfirst's right to exchange its working interest for Ivanhoe common shares expires in December 2005. CITIC also has committed to assist in arranging non-recourse project financing for the remainder of the Dagang development program.

The production-sharing contract stipulates that we have the right to market our oil domestically or export it, sell our product in U.S. dollars and receive world market prices for our product. We are currently selling our crude oil to CNPC at a three-month rolling average price of Cinta crude oil, which historically has averaged approximately $2.00 per barrel less than the West Texas Intermediate

("**WTI**") price. Cinta is an Indonesian crude that is traded daily on the international oil market.

All petroleum producers in China pay a value added tax of 5% on oil production. We pay no royalty until annual gross production of crude oil from a particular block within the Dagang field exceeds 500,000 tonnes per annum. Royalties then become payable at a rate of 2% and increase incrementally as the rate of production increases to a maximum of 12.5% once annual gross production on a block exceeds four million tonnes. Our entire interest in the Dagang field will revert to CNPC at the end of the 20-year production phase of the contract or if we abandon the field earlier.

During 2001, we completed the pilot phase and in 2002 submitted the final draft of our ODP to the Chinese regulatory authorities for approval. Final government approval was obtained in April 2003, after which the development phase commenced in late 2003. In 2004, we drilled 19 development wells of which 16 were completed and placed on production. The year-end 2004 gross production rate was 1,655 Bopd. To complete the ODP over the next three years, we expect to drill 90 new wells and rework an additional 28 of the 82 existing wells at an estimated cost to Ivanhoe of $113 million.

- ***Sichuan Basin***

In February 2001, we signed two memoranda of understanding with PetroChina. These memoranda gave us the exclusive right to negotiate production-sharing contracts for the Zitong and Yudong land blocks in Sichuan Province, which cover an area of approximately 2.2 million acres. We agreed with PetroChina to carry out joint feasibility studies on the blocks located in the Sichuan Basin, approximately 930 miles southwest of Beijing. In September 2002, we signed a production-sharing contract (the "**Zitong Contract**"), with CNPC. The Zitong Contract received final Chinese regulatory approval in November 2002.

Under the Zitong Contract, we agreed to conduct an exploration program on the Zitong block consisting of two phases, each three years in length. The parties will jointly participate in the development and production of any commercially viable deposits, with production rights limited to a maximum of the lesser of 30 years following the date of the Zitong Contract or 20 years of continuous production.

During the first phase of exploration, we must complete a minimum work program consisting of reprocessing approximately 1,250 miles of seismic data, completing approximately 300 additional miles of new seismic lines and drilling and completing two wells totaling at least 23,000 feet, with estimated minimum expenditures for the program of $18 million. Upon completion of the first phase, we must relinquish up to 30% of the Zitong block. During 2003 and 2004, we reprocessed approximately 1,550 miles of existing seismic data and acquired approximately 540 miles of a 700-mile seismic acquisition program. Following processing and interpretation of the seismic data, we selected the location of our first exploration well and expect to spud the well in the first quarter of 2005.

If we elect to participate in phase two, we must complete a minimum work program consisting of new seismic lines totaling approximately 200 miles and drill and complete two additional wells totaling approximately 23,000 feet, with estimated minimum expenditures for the program of $16 million. Following the completion of phase two, we must relinquish all of the property except any areas identified for development and production.

We can elect to commence the development of commercially viable deposits at any time following the submission of an ODP. Once we complete phase one of the exploration project, we can also elect not to proceed with phase two of the exploration project. However, once we commence a phase of the exploration project we must complete the minimum work program or we will be obligated to pay, to CNPC, the cash equivalent of the deficiency in the work program for that exploration phase.

If we identify a field for development and/or production, the parties will divide the participating interest in the project, with CNPC entitled to fund and take up to 51% of the participating interest.

Once commercial production commences, we will recover annual exploration, development and operating costs from up to 60% of gross oil production and 70% of gross natural gas production. After annual cost recovery, we are entitled to production equaling our participating interest, subject to certain additional rights of the Chinese government. Assuming we hold a 49% participating interest, we will be entitled to approximately 75% of production initially, declining to approximately 45% after full exploration and development cost recovery.

CNPC retains the rights to production from six existing wells located on the Zitong block. We can drill new wells on the same structure as those tapped by the existing wells, but our wells must be no closer than 3,280 feet from the existing wells.

In 2003, we established an office in Chengdu, the capital of Sichuan. We have also completed our feasibility study obligations for the Yudong block and submitted a report to PetroChina in April 2002. In September 2002, we submitted a letter of intent to negotiate a production-sharing contract and our work plan for the Yudong block, and are currently awaiting PetroChina's reply.

- ***CITIC Alliance***

In October 2002, we entered into an agreement with CITIC Energy Ltd. ("**CITIC Energy**") to form a strategic alliance to seek out and develop oil and gas projects in China and around the world. CITIC Energy is a subsidiary of CITIC, a major Chinese state-owned enterprise that holds interests in a wide range of industries.

Under the terms of the agreement, CITIC Energy will assist Sunwing in raising its profile in Asian capital markets and gaining access to future financing opportunities. CITIC Energy will also support Sunwing in its plan to obtain a listing for its shares on the Stock Exchange of Hong Kong.

We are expected to assist CITIC Energy in identifying and acquiring interests in international oil and gas development projects and in introducing GTL and other advanced energy-sector technologies to China's domestic oil and gas industry. We hold a master license to Syntroleum's proprietary GTL process, the geographical scope of which includes China.

CITIC Energy has also agreed to assist us in our efforts to negotiate a production-sharing contract with PetroChina covering the Yudong block in the Sichuan Basin. Should a production-sharing contract for the Yudong block be obtained, Sunwing and CITIC Energy will jointly participate in the development of the project on a 70/30 basis. Within 180 days thereafter, either party can elect to convert CITIC Energy's 30% participating interest in the project into a 20% equity interest in Sunwing. CITIC Energy has the right to appoint a representative to Sunwing's Board of Directors and will be entitled to appoint a second representative if, as and when it acquires a 20% equity interest in Sunwing.

In April 2003, we entered into a further agreement with CITIC Energy that enables both companies to form a global strategic alliance to investigate, explore and develop oil, natural gas, metallurgical coal, liquefied natural gas and GTL projects in China and around the world, to help supply China's future energy requirements. The new agreement builds upon the initial partnership formed between the two companies in October 2002 and follows discussions both between the two companies and with asset owners of potential projects in China and in other parts of the world.

ENHANCED OIL RECOVERY AND HEAVY-TO-LIGHT OIL PROJECTS

- ***Ensyn***

The Ensyn RTP™ Technology, patented in the U.S., Canada and other countries, upgrades the quality of heavy oil by producing lighter, more valuable crude oil. Ensyn reports that this process dramatically improves the economics in heavy-oil projects. The heaviest hydrocarbon fraction is consumed as fuel to generate the steam used to enhance recovery of heavy crude. This lowers costs by reducing or eliminating the need to purchase high-priced natural gas for steam generation and improves revenue since the higher quality light-crude fraction can be sold at higher prices. The lighter crude has improved viscosity that permits more efficient pumping through pipeline networks and significantly reduces transportation costs to marketing points. The Ensyn RTP™ Technology uses readily available plant and process components.

The RTP™ Technology already has been successfully applied to continuous wood/biomass processing, in six commercial plants in operation in Canada and the U.S. A seventh biomass plant is under construction in Canada. The technology has recently been applied to petroleum processing and an Ensyn pilot plant in Ontario, Canada has completed more than 90 test runs on heavy oil. In addition, Ensyn's 1,000-barrel-per-day CDF, located in the Belridge heavy oil field near Bakersfield, California, successfully started up in December 2004. Ensyn currently plans to use the facility to process local heavy oil, as well as to test a range of heavy crudes from around the world.

During 2004, we acquired, for $3.0 million, a 15% equity interest in EPIL and exclusive rights to use the proprietary Ensyn RTP™ Technology in key international markets in China, Mongolia, Iraq, Oman and all countries in South America except Venezuela. In these countries, we have exclusive rights to use the Ensyn RTP™ Technology for an initial term of five years until January 2009, subject to extension if and when commercial plants are constructed. For each project we develop using the Ensyn RTP™ Technology in our exclusive territories, Ensyn could elect to receive an equity participation in the project for the same proportionate cost we paid. The participation that may be obtained by Ensyn could be no more than 10%, except for each such project that we develop in South America, other than in Peru, where Ensyn could elect to receive an equity interest equal to 25% of our interest. Ensyn's equity position would offset and eliminate the payment of license fees for use of the Ensyn RTP™ Technology in the project.

On December 11, 2004, Ivanhoe, Ivanhoe Merger Sub, Inc. ("**Merger Sub**"), a Delaware corporation and our wholly-owned subsidiary, and Ensyn entered into an Agreement and Plan of Merger (the "**Merger Agreement**"), pursuant to which Merger Sub will be merged with and into Ensyn and Ensyn will become our wholly owned subsidiary (the "**Merger**") and all of the issued and outstanding shares of Ensyn common stock will be converted into the right to receive cash and common shares of Ivanhoe.

We have agreed to pay $10 million in cash and issue Ivanhoe common shares ("**Merger Shares**") in exchange for all of the issued and outstanding Ensyn common shares and all unissued Ensyn common shares issuable upon the future exercise of any purchase warrants that remain unexercised when the Merger takes effect. The number of Merger Shares to be issued will be the greater of: (i) 30,000,000 or (ii) the quotient obtained by dividing $75 million by the weighted average of the closing prices of Ivanhoe common shares on the NASDAQ SmallCap Market over a period of ten consecutive trading days determined five business days prior to the scheduled date of a special meeting of the shareholders of Ensyn at which their approval of the Merger will be sought.

One-third of the total number of Merger Shares issued will be deposited and held in an escrow fund (the "**Indemnity Escrow Fund**") to secure certain obligations on the part of the Ensyn shareholders and to indemnify us for damages arising from breaches of warranties and covenants under, and other circumstances more particularly described in, the Merger Agreement. Subject to any prior claims by us for indemnification, one-half of the Merger Shares in the Indemnity Escrow Fund will be released to the Ensyn shareholders no later than 20 days from (i) the date that we, Ensyn or any of our respective controlled affiliates enters into a definitive agreement with an unaffiliated third party for the construction or use of a processing plant equipped with the RTP™ Technology and having a minimum daily input processing capacity of 10,000 barrels of oil per day (an "**RTP™ Plant**") or (ii) the second anniversary of the closing date of the Merger, whichever is earlier. The balance of the Merger Shares in the Indemnity Escrow Fund will be released, subject to any prior claims by us for indemnification, as of (i) the second anniversary of the date that we, Ensyn or any of our respective controlled affiliates enters into a definitive agreement with an unaffiliated third party for the construction or use of an RTP™ Plant, (ii) the second anniversary of the date that we or any of our controlled affiliates commences construction of an RTP™ Plant, (iii) the date that we, Ensyn or any of our respective controlled affiliates enters into a second definitive agreement with an unaffiliated third party for the construction or use of an RTP™ Plant, (iv) the date that we or any of our controlled affiliates commences construction of a second RTP™ Plant, and (v) the third anniversary of the closing date of the Merger, whichever is earliest but, in any event, no earlier than the first anniversary of the closing date of the Merger.

Ensyn currently uses the RTP™ Technology in two ways: a biomass process that transforms wood and other organic material into bio-fuels, resins and other products (the "**Renewables Business**") and a petroleum process that upgrades heavy oil and bitumen, into lighter, less viscous petroleum products (the "**Petroleum Business**"). The Merger Agreement provides that Ensyn will use commercially reasonable efforts to distribute to its shareholders, by way of a dividend prior to the Merger taking effect, all of the issued and outstanding shares of a newly formed wholly owned subsidiary that, prior to such distribution, will indirectly own and operate the Renewables Business. Ensyn will retain the Petroleum Business when it becomes our wholly owned subsidiary pursuant to the Merger. Upon the Merger taking effect, we will thereafter share the intellectual property rights in the RTP™ Technology with Ensyn through a series of cross-licensing and non-competition arrangements.

Upon the implementation of the Merger, two individuals designated by Ensyn will be appointed to our Board of Directors. We have agreed to use our reasonable best efforts to nominate Ensyn's designees for re-election to our Board of Directors annually for at least five years.

The respective obligations of the parties to consummate the Merger are subject to a number of conditions precedent customary in similar transactions. These conditions include the adoption of the Merger Agreement and the approval of the Merger by a majority of the votes cast by the Ensyn shareholders at a special meeting to be convened for that purpose and, if the number of Merger Shares to be issued, together with any other common shares of Ivanhoe issued or issuable pursuant to any private placement equity financing transactions undertaken by us in connection with the Merger, exceeds the maximum number of common shares that we would be permitted to issue without shareholder approval under the applicable rules of the Toronto Stock Exchange, approval of the issuance of such Ivanhoe common shares by a majority of the votes cast by our shareholders at a special meeting to be convened for that purpose.

Our obligation to effect the Merger is also subject to Ensyn's RTP™ Technology-equipped commercial demonstration facility in California having satisfied certain technical performance requirements and criteria provided for in the Merger Agreement. This condition will be satisfied when we receive reports from certain third party technical consultants confirming that the facility has met the requisite requirements and criteria.

The transactions contemplated by the Merger Agreement are expected to close early in the second quarter of 2005. Either we, or Ensyn, may elect to terminate the Merger Agreement if the Merger has not been consummated by May 15, 2005, subject to an extension of up to sixty days in certain circumstances more particularly described in the Merger Agreement. There can be no assurance that the transactions contemplated by the Merger Agreement will be consummated.

The Boards of Directors of both Ivanhoe and Ensyn have approved the merger transaction. In reaching its decision to approve the merger transaction, our Board of Directors considered a variety of factors, a number of which are summarized below:

- *Acquiring innovative petroleum production technology is a key aspect of our corporate strategy.* A key aspect of our corporate strategy is to grow our business by expanding our oil and gas reserve base. Although part of this strategy involves

conventional exploration and production, our management recognizes that we lack the size and the significant financial resources necessary to pursue the conventional exploration and production growth strategies historically undertaken by large, integrated oil companies. The core of our corporate strategy is to accelerate the development of our business by leveraging the experience, expertise and existing business relationships of our senior management personnel. We seek projects requiring relatively low initial capital outlays to which we can apply innovative technology and enhanced recovery techniques in developing them. Our Board of Directors believes that the acquisition of Ensyn's RTP™ Technology will represent a major advance in the implementation of our corporate strategy in that it offers significant potential for broadening our access to project opportunities that might not otherwise be available to us.

- *Ensyn's RTP™ Technology represents a unique approach to heavy oil upgrading.* The innovative characteristics of Ensyn's RTP™ Technology offer the means to technologically and economically improve the production and marketing of heavy oil in the petroleum industry. Current test results from over 90 test runs on heavy oil at Ensyn's pilot plant in Ontario show that the RTP™ Technology offers a means of improving the value of heavy, sour crude oils in a manner that is comparable to established coking technologies but at significantly lower operating and capital costs. In addition, these test results evidence that the RTP™ Technology reduces or eliminates the need for an external energy source (usually natural gas, for steam production used in the recovery process), reduces the viscosity of the heavy oil and also permits the use of the processed oil to be used as a blending agent to facilitate the transportation of heavy oil by pipeline.

- *Heavy oil represents a vast untapped resource.* Heavy oil deposits throughout the world represent a potentially massive resource, holding quantities of heavy oil more than double the existing global reserves of light or conventional oil. Heavy oil extraction and transportation presents a number of technological challenges and typically requires extensive and cost-intensive infrastructure. Higher viscosity makes the transportation of heavy oil through conventional pipelines difficult or impossible unless it is first blended with lighter, lower viscosity oil or expensive diluents. As a result, less than 1% of the world's heavy oil deposits are currently under active development. Our Board of Directors believes that Ensyn's RTP™ Technology offers us the unique opportunity to accumulate reserves by acquiring interests in "stranded" heavy oil deposits that would otherwise be uneconomic to develop through conventional means and developing them on an incremental, cost-efficient basis using Ensyn's RTP™ Technology.

- *Application of Ensyn's RTP™ Technology to heavy oil deposits offers potentially significant economic benefits.* Our Board of Directors believes that, if the Ensyn RTP™ Technology can be deployed on a commercial scale, it will offer a number of potential cost saving and revenue-enhancement benefits. The reduction or elimination of the need for an external energy source, usually natural gas, for steam production used in the heavy oil recovery process, often a substantial added cost to conventional producers, could significantly reduce the operating cost of extracting the heavy oil. The RTP™ Technology upgraded oil is likely to command a higher market price, reducing what would otherwise be a significant price differential between heavy and light oil. The price paid to producers for heavy oil is lower than the price paid for light oil as the heavy oil requires additional refining. Unlike conventional heavy oil extraction facilities, which usually must be constructed on a large scale in order to be economical and therefore require a significant up-front capital investment, we expect to be able to deploy the RTP™ Technology on a relatively small scale and independent of refineries, which should allow us to develop smaller heavy oil fields that would otherwise be uneconomic to exploit using conventional technologies. The scalability of RTP™ Technology-equipped facilities offers the potential to develop heavy oil deposits on an incremental basis financed by cash flow. Given their limited infrastructure requirements, RTP™ Technology-equipped facilities can be located in relatively remote areas where constructing conventional facilities would not be feasible.

- *Exclusive control of Ensyn's RTP™ Technology in its application to petroleum processing gives us an important strategic advantage.* Although we already hold exclusive licensing rights to deploy Ensyn's RTP™ Technology in petroleum processing projects in a number of countries, including China, Mongolia, Iraq, Oman and most of South America and non-exclusive rights to use the technology elsewhere in the world, exclusive control of the technology throughout the world increases our leverage in the pursuit of our strategic plans and objectives. We believe that the value of the technology can be maximized by using it to create opportunities to acquire interests, and actively participate, in heavy oil development projects rather than licensing the technology to third parties and collecting passive licensing payments. The acquisition of Ensyn will advance this strategy by giving us the exclusive right, subject to limited pre-existing licensing rights, to deploy the RTP™ Technology anywhere in the world, including in the key North American markets. At the same time, the acquisition will effectively result in us re-acquiring from Ensyn the future project participation rights (between 10% and 25%) we granted to Ensyn when we first acquired exclusive licensing rights in the technology and will minimize our obligations to pay licensing fees in respect of those projects we develop using the technology.

- *Combining the technical expertise of Ensyn's personnel with the international petroleum industry experience and expertise of our personnel will benefit us.* Our Board of Directors believes that aligning the interests of Ensyn's shareholders with those of our shareholders ensures that we will continue to enjoy access to the benefits of the scientific and technological expertise possessed by Ensyn's personnel. Our management team has been working closely with key members of Ensyn's management

team, including Ensyn's co-founders, for nearly two years. The acquisition of Ensyn should create synergies between the technical expertise of Ensyn's personnel and the international petroleum industry experience and expertise of our personnel and result in a more integrated Ivanhoe/Ensyn management team for the deployment of the RTP™ Technology, as the former Ensyn shareholders will become significant shareholders in our company and two members of Ensyn's management will join our Board of Directors.

- ***Iraq***

In October 2004, we signed a memorandum of understanding ("**MOU**") with the Ministry of Oil of the Government of Iraq to study and evaluate the shallow Qaiyarah oil field in Iraq. The field's reservoirs contain a large proven accumulation of 17.1° API heavy oil at a depth of about 1,000 feet.

We will evaluate the potential response of the Qaiyarah oil field to the latest in EOR techniques, along with the potential value that could be added using the Ensyn RTP™ Technology to produce higher quality, more valuable crude oil. The work will include an assessment of the oil-in-place in the reservoirs, and the optimum EOR/HTL methods to establish economically recoverable volumes at the Qaiyarah oil field.

If the evaluation studies indicate development of the field is economically viable, we will present a development plan and offer a commercial proposal to implement an EOR program for the Qaiyarah oil field. The Iraqi Ministry of Oil is under no obligation to execute the project or to enter into formal commercial negotiations at the completion of our study.

- ***Colombia***

In December 2004, we signed an MOU with Ecopetrol S.A. ("**Ecopetrol**") for a study of the heavy crudes from the large Castilla and Chichimene oil fields in Colombia. The two oil fields are about 75 miles southeast of Bogotá in the Central Llanos Basin. This region is an active oil producing area and the Castilla and Chichimene fields have successfully been producing oil since the 1970's.

In the initial phase, we will run tests on the two heavy crudes to determine the value that could be added to these fields using the Ensyn RTP™ Technology.

Ecopetrol S.A., formerly Empresa Colombiana de Petroleos, is a public company with 100% of its shares currently owned by the Republic of Colombia. Ecopetrol is exclusively devoted to searching for, producing, transporting, storing, refining and marketing hydrocarbons and is the fourth largest national oil company in Latin America. Gross oil production in 2003, by Ecopetrol and its associates, was 541,000 Bopd, and year-end reserves were over 1.5 billion barrels.

GAS-TO-LIQUIDS PROJECTS

Syntroleum License

We hold a non-exclusive master license entitling us to use Syntroleum's proprietary GTL process in an unlimited number of projects with no limit on production volume. In June 2003, we gave up our rights for license fee credits for the $10.0 million we paid for the master license and $2.0 million we invested in Syntroleum's Sweetwater project. In consideration, Syntroleum removed certain territorial restrictions to our master license, which will enable us to pursue GTL project opportunities worldwide, particularly in China. Syntroleum has also agreed that, in respect of GTL projects in which both companies participate, no additional license fees or royalties will be payable and that Syntroleum will also contribute to any such project the right to manufacture specialty and lubricant products. Both companies have the right to pursue GTL projects independently, but we would be required to pay Syntroleum the normal license fees and royalties in such projects.

Syntroleum Process

Syntroleum's proprietary GTL process is designed to catalytically convert natural gas into synthetic liquid hydrocarbons. This patented process uses compressed air, steam and natural gas as initial components to the catalyst process. As a result, this process (the "**Syntroleum Process**") substantially reduces the capital and operating costs and the minimum economic size of a GTL plant as compared to the other oxygen-based GTL technologies.

Syntroleum developed its GTL technology based on a process developed in Germany in the 1920s for the gasification of coal into oil, called the Fischer-Tropsch reaction. Syntroleum has applied its principles to the conversion of natural gas to synthetic liquid hydrocarbons. Syntroleum believes that it holds a competitive advantage over other GTL technologies because the Syntroleum Process uses air when converting natural gas into synthetic hydrocarbons. Competitor GTL processes use either steam reforming or a combination of steam reforming and partial oxidation with pure oxygen. A steam reformer and an air separation plant necessary for

oxidation are expensive and considered hazardous and increase operating costs.

From our perspective, the attraction of the Syntroleum Process lies in the commercialization of stranded natural gas. Such gas exists in discovered and known reservoirs, but requires innovative gas processing to produce products that can be marketed on an economic basis. Operators consider natural gas to be stranded based on the relative size of the fields and their remoteness from comparable sized markets.

GTL Projects

We have performed detailed project feasibility studies for the construction, operation and cost of GTL plants in both Qatar and Egypt. In May 2003, advanced negotiations with Qatar Petroleum and the Qatari government to construct and operate such a facility terminated without an agreement being reached. In the quarter ended June 30, 2003, we wrote down $3.3 million of our GTL investments for expenditures incurred in connection with these negotiations. In the second quarter of 2004, we wrote down our $0.3 million investment in the Oman GTL project as our opportunity to build a 45,000-barrels per day GTL fuels plant in Oman failed to materialize due to a lack of sufficient uncommitted gas volumes.

We have conducted marketing and transportation feasibility studies for both European and Asia Pacific regions in which we identified potential markets and estimated premiums for GTL diesel and GTL naphtha. Based on our ongoing commercialization studies and the growing demand for cleaner sources of energy in Japan, we incorporated GTLJ to facilitate the potential future participation by Japanese companies in GTL projects. In November 2004, we changed the name of GTLJ to ERDJ and expanded the charter of the company to include participation of multi-national companies in EOR projects, including those involving HTL oil upgrading. Should we be successful in obtaining the rights to develop such projects, we intend to assign a certain percentage of our interest in the project to ERDJ. We would then invite multi-national companies from the refining and distribution, exploration and production, and trading and manufacturing industry sectors to invest in ERDJ. The proceeds raised would be used to fund a portion of the total project capital costs, including front-end engineering and design.

In 2004, we initiated a feasibility study to convert coal to synthesis gas ("**CTL**") as a feedstock for the Syntroleum Fischer-Tropsch process. The objective of the study is to explore opportunities for converting coal into clean burning CTL fuels in parts of the world where there is a relatively cheap supply of sizeable coal deposits. China in particular, has large coal deposits and a rapidly growing need for clean energy.

- ***Egypt***

The feasibility studies we have undertaken for Egypt contemplate the natural gas feedstock being purchased, rather than developed. A preliminary feasibility study for a 45,000 barrels per day fuels, specialty products and lubricants GTL plant in Egypt was completed and presented to the government of Egypt and its agencies responsible for the development and monetization of its natural gas reserves. The Egyptian governmental agencies are now making economic comparisons of the three alternative methods for gas monetization that they have available to them: (1) pipeline exports to Syria and Jordan, (2) liquefied natural gas exports to Europe and (3) GTL. This is an ongoing analysis and we believe our GTL proposal remains a viable alternative for Egypt. Discussions continue with Egyptian officials to promote the GTL alternative. Accordingly, we have recently initiated a new detailed GTL fuels plant engineering feasibility and product price study that takes full advantage of the latest advancements in the Syntroleum technology.

- ***Bolivia***

In July 2003, we signed a participation agreement with Repsol-YPF Bolivia S.A. ("**Repsol**") and Syntroleum for a commercialization study to build a 90,000-barrel-per-day GTL plant in southern Bolivia. The commercialization study includes an analysis of alternative plant sites, transportation logistics and screening economics conducted by representatives from Ivanhoe, Repsol and Syntroleum. The initial phase of the commercialization study was completed in 2004 and we determined that under Bolivia's current hydrocarbon tax regulations a 90,000-barrel-per-day GTL plant could be commercially viable. However, due to the passing of a referendum to overhaul Bolivia's tax regulations in the third quarter of 2004 we elected to postpone any further work on the commercialization study. The participation agreement with Repsol and Syntroleum expired at the end of 2004 and we elected not to renew the participation agreement. We continue to pursue other opportunities in Bolivia for monetization of the country's vast natural gas deposits into GTL fuels.

RISK FACTORS

We are subject to a number of risks due to the nature of the industry in which we operate, our reliance on strategies which include technologies that have not been proved on a commercial scale, the present state of development of our business and the foreign jurisdictions in which we carry on business. The following factors contain certain forward-looking statements involving risks and

uncertainties. Our actual results may differ materially from the results anticipated in these forward-looking statements.

We cannot guarantee the successful commercialization of our exploration activities.

We have exploration and development projects in the U.S. and China. Our projects are at various stages and, like all exploration companies in the oil and gas industry, we are exposed to the significant risk that our exploration activities will not necessarily result in a discovery of economically recoverable volumes.

We have a history of losses and must generate greater revenue to achieve profitability.

We commenced operations in 1997 and have been involved in three start-up situations in Russia, China and the U.S. Like most start-up companies we have incurred losses during our start-up activities. Our current cash flows alone are insufficient to fund our medium and long-term business plans, necessitating further growth and funding for implementation. We may be unable to achieve the needed growth to obtain profitability and may fail to obtain the funding that we need when it is required.

We are not able to guarantee the successful commercial development of our licensed GTL technology.

To date, no commercial-scale GTL plants have been constructed using the proprietary GTL process we license from Syntroleum and, therefore, the process has not been proven on a commercial scale. Other developers of GTL technology have significantly more financial resources than we do and may be able to use this to obtain a competitive advantage.

We may not be able to conclude a GTL development and production-sharing contract.

We were unsuccessful in concluding a GTL development and production-sharing contract in Qatar and we can give no assurances as to when or if we will be able to conclude such contracts in Egypt, Bolivia or other countries where we are now, or will be, exploring GTL project opportunities.

We are not able to guarantee the successful commercial development of Ensyn's RTP™ Technology.

To date, no commercial-scale HTL plants have been constructed using the Ensyn RTP™ Technology and, therefore, the process has not been proven to be financially viable on a commercial scale. Other developers of competing HTL technologies may have significantly more financial resources than we do and may be able to use this to obtain a competitive advantage.

We may not be able to conclude HTL joint venture or production-sharing contracts using the RTP ™ Technology.

We have signed memoranda of understanding in Iraq and Colombia to study the economic feasibility of an RTP™ Technology HTL oil processing facility for specified oil fields in those countries but we can give no assurances as to when or if we will be able to conclude a joint venture or production-sharing contract with the governments in those countries or any other countries where we are now, or will be, seeking HTL project opportunities.

Commercialization of our GTL or HTL projects may give rise to claims of infringement upon the patents or proprietary rights of others.

We own licenses to employ Syntroleum's GTL and Ensyn's RTP™ Technology processes but we may not become aware of claims of infringement upon the patents or rights of others in these respective technologies until after we have made a substantial investment in the development and commercialization of projects utilizing these licensed technologies. Third parties may claim that the technologies we license have infringed upon past, present or future patented technologies. Legal actions could be brought against the licensor and us claiming damages and seeking an injunction that would prevent us from testing or commercializing the affected technologies. If an infringement action were successful, in addition to potential liability for damages, we and our licensors could be required to obtain a claiming party's license in order to continue to test or commercialize the affected technologies. Any required license might not be made available or, if available, might not be available on acceptable terms, and we could be prevented entirely from testing or commercializing the affected licensed technology. We may have to expend substantial resources in litigation defending against the infringement claims of others. Many possible claimants, such as the major energy companies that have or may be developing proprietary GTL or HTL technologies competitive with the Syntroleum and RTP™ Technology processes that we license, may have significantly more resources to spend on litigation.

Ensyn has a history of operating losses and may continue to incur losses in the future.

Since its inception, Ensyn has invested a significant amount of time and money in the research and development of new products. Its development expense, including development of licensing fees, was $0.9 million and $0.6 million for the years ended September 30,

2004 and 2003, respectively. Its total operating expense, including development costs, was $1.8 million and $1.0 million for the years ended September 30, 2004 and 2003, respectively, compared to total revenue of $0.3 million and $0.7 million, respectively, for such periods. Ensyn had net losses of $1.2 million and $0.6 million for the years ended September 30, 2004 and 2003, respectively. Ensyn's accumulated deficit as of September 30, 2004 was $14.4 million. If we incur losses in our application of the RTP™ Technology after completion of the Ensyn acquisition, this may have an adverse impact on our operating results, which could cause the market price of our shares to decline.

Technological advances could significantly decrease the cost of upgrading petroleum, and if we are unable to adopt or incorporate technological advances into our operations, the RTP™ Technology could become uncompetitive or obsolete.

We expect that technological advances in the processes and procedures for upgrading heavy oil and bitumen into lighter, less viscous products will continue to occur. It is possible that those advances could make the processes and procedures that are presently being utilized by Ensyn (and which we intend to utilize after the acquisition) less efficient or cause the upgraded product currently being produced by Ensyn to be of a lesser quality. These advances could also allow competitors to produce upgraded products at a lower cost than that at which Ensyn is currently able to produce such products. If we are unable to adopt or incorporate technological advances, our production methods and processes could be less efficient than those of our competitors, which could cause RTP™ Technology plants to become uncompetitive.

In addition, alternative sources of energy are continually under development. Alternative energy sources that can reduce reliance on oil and bitumen may be developed, which may decrease the demand for RTP™ Technology upgraded product. It is also possible that technological advances in engine design and performance could reduce the use of oil and bitumen, which would lower the demand for such products.

Conflict in the Middle East may hamper our GTL, EOR and HTL project objectives.

Ongoing tensions and conflict in the Middle East could harm our business in the short to medium term by making it difficult or impossible to continue our pursuit of GTL, EOR and HTL projects in the region or to obtain financing for projects we do succeed in obtaining. It is impossible to predict the occurrence of such events, how long they will last, the economic consequences of the conflict for the energy industry, regionally and globally, and how our business might be affected over the longer term.

Crude oil and natural gas prices are volatile.

Fluctuations in the prices of oil and natural gas will affect many aspects of our business, including our revenues, cash flows and earnings; our ability to attract capital to finance our operations; our cost of capital; the amount we are able to borrow and the value of our oil and natural gas properties.

Both oil and natural gas prices are extremely volatile. Oil prices are determined by international supply and demand. Political developments, compliance or non-compliance with self-imposed quotas, or agreements between members of the OPEC can affect world oil supply and prices. Any material decline in prices could result in a reduction of our net production revenue and overall value. The economics of producing from some wells could change as a result of lower prices. As a result, we could elect not to produce from certain wells. Any material decline in prices could also result in a reduction in our oil and natural gas acquisition and development activities.

In addition, a material decline in oil and natural gas prices from historical average prices could adversely affect our ability to borrow and to obtain additional capital on attractive terms.

Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploration projects.

Government regulations in foreign countries may limit our activities and harm our business operations.

In addition to our interest in our China projects, we may enter into contractual arrangements to acquire oil and gas properties in other foreign jurisdictions with governments, governmental agencies or government-owned entities. The foreign legal framework for these agreements, particularly in developing countries, is often based on recent political and economic reforms and newly enacted legislation, which may not be consistent with long-standing local conventions and customs. As a result, there may be ambiguities, inconsistencies and anomalies in the agreements or the legislation upon which they are based which are atypical of more developed legal systems and which may affect the interpretation and enforcement of our rights and obligations and those of our foreign partners. Local institutions and bureaucracies responsible for administering foreign laws may lack a proper understanding of the laws or the experience necessary to apply them in a modern business context. Foreign laws may be applied in an inconsistent, arbitrary and unfair

manner and legal remedies may be uncertain, delayed or unavailable.

We may not be successful in negotiating additional production-sharing contracts in China.

We hold our interests in China through two production-sharing contracts with CNPC for the Dagang and Zitong blocks. We also have an MOU with PetroChina indicating a mutual intention to negotiate an additional production-sharing contract in the Sichuan basin. We cannot assure you, based on our existing MOU with PetroChina, that we will successfully negotiate additional production-sharing contracts. It is possible that disputes between us could arise in the future, which must be resolved under foreign law. We cannot be sure that we can enforce our legal rights in foreign countries or that an effective legal remedy will be available to us in any dispute governed by foreign law.

We might not be successful in acquiring and developing new prospects and our exploration and development properties may not contain any significant proved reserves.

Our future exploration and development success depends upon our ability to find, develop and acquire additional economically recoverable oil and natural gas reserves. The successful acquisition and development of oil and gas properties requires proper forecasting of recoverable reserves, oil and gas prices and operating costs, potential environmental and other liabilities and productivity of new wells drilled.

Estimates of cost to explore, develop and produce are assessments and are inexact. As a result, we might not recover the purchase price of a property from the sale of production from the property, or might not recognize an acceptable return from properties we acquire. Our estimates of exploration, development and production costs can be affected by such factors as permitting regulations and requirements, weather, environmental factors, unforeseen technical difficulties and unusual or unexpected formations, pressures and work interruptions.

Exploration and development involves significant risks. Few wells, which are drilled, are developed into commercially producing fields. Substantial expenditures may be required to establish the existence of proved reserves, and we cannot assure you commercial quantities of oil and gas deposits will be discovered sufficient to enable us to recover our exploration and development costs or be sufficient to sustain our business.

Expansion of our operations will require significant capital expenditures for which we may be unable to provide sufficient financing. Our need for additional capital may harm our financial condition.

We will be required to make substantial capital expenditures far beyond our existing capital resources to develop a GTL, EOR or HTL project, to exploit our existing reserves and to discover new oil and gas reserves. Historically, we have relied, and continue to rely, on external sources of financing to meet our capital requirements to continue acquiring, exploring and developing oil and gas properties and to otherwise implement our corporate development and investment strategies. We have, in the past, relied upon equity capital as our principal source of funding. We plan to obtain the future funding we will need through debt and equity markets, but we cannot assure you that we will be able to obtain additional funding when it is required and whether it will be available on commercially acceptable terms. We also make offers to acquire oil and gas properties in the ordinary course of our business. If these offers are accepted, our capital needs may increase substantially. If we fail to obtain the funding that we need when it is required, we may have to forego or delay potentially valuable opportunities to acquire new oil and gas properties or default on existing funding commitments to third parties and forfeit or dilute our rights in existing oil and gas property interests. Our limited operating history may make it difficult to obtain future financing.

You should not unduly rely on reserve information because reserve information represents estimates.

Reserve estimates involve a great deal of uncertainty, because they depend in large part upon the reliability of available geologic and engineering data, which is inherently imprecise. Geologic and engineering data are used to determine the probability that a reservoir of oil and natural gas exists at a particular location, and whether oil and natural gas are recoverable from a reservoir. Recoverability is ultimately subject to the accuracy of data including, but not limited to geological characteristics of the reservoir structure, reservoir fluid properties, the size and boundaries of the drainage area and reservoir pressure and the anticipated rate of pressure depletion.

The evaluation of these and other factors is based upon available seismic data, computer modeling, well tests and information obtained from production of oil and natural gas from adjacent or similar properties, but the probability of the existence and recoverability of reserves is less than 100% and actual recoveries of proved reserves usually differ from estimates.

Reserve estimates also require numerous assumptions relating to operating conditions and economic factors including, among others, the price at which recovered oil and natural gas can be sold, the costs of recovery, prevailing environmental conditions associated with drilling and production sites, availability of enhanced recovery techniques, ability to transport oil and natural gas to markets and

governmental and other regulatory factors, such as taxes and environmental laws.

A negative change in any one or more of these factors could result in quantities of oil and natural gas previously estimated as proved reserves becoming uneconomic. For example, a decline in the market price of oil or natural gas to an amount that is less than the cost of recovery of such oil and natural gas in a particular location could make production thereof commercially impracticable. The risk that a decline in price could have that effect is magnified in the case of reserves requiring sophisticated or expensive production enhancement technology and equipment, such as some types of heavy oil. Each of these factors, by having an impact on the cost of recovery and the rate of production, will also affect the present value of future net cash flows from estimated reserves.

In addition, estimates of reserves and future net cash flows expected from them prepared by different independent engineers, or by the same engineers at different times, may vary substantially.

Information in this document regarding our future plans reflects our current intent and is subject to change.

We describe our current exploration and development plans in this document. Whether we ultimately implement our plans will depend on availability and cost of capital; receipt of additional seismic data or reprocessed existing data; current and projected oil or gas prices; costs and availability of drilling rigs and other equipment, supplies and personnel; success or failure of activities in similar areas; changes in estimates of project completion costs; our ability to attract other industry partners to acquire a portion of the working interest to reduce costs and exposure to risks and decisions of our joint working interest owners.

We will continue to gather data about our projects and it is possible that additional information will cause us to alter our schedule or determine that a project should not be pursued at all. You should understand that our plans regarding our projects might change.

Our business may be harmed if we are unable to retain our licenses, leases and working interests in licenses and leases.

Some of our properties are held under licenses and leases and working interests in licenses and leases. If we, or the holder of the license or lease, fail to meet the specific requirements of each license or lease, the license or lease may terminate or expire. We cannot assure you that any of the obligations required to maintain each license or lease will be met. The termination or expiration of our licenses or leases or our working interest relating to a license or lease may harm our business. Some of our property interests will terminate unless we fulfill certain obligations under the terms of our agreements related to such properties. If we are unable to satisfy these conditions on a timely basis, we may lose our rights in these properties. The termination of our interests in these properties may harm our business.

Complying with environmental and other government regulations could be costly and could negatively impact our production.

Our operations are governed by numerous laws and regulations at various levels of government in the countries in which we operate. These laws and regulations govern the operation and maintenance of our facilities, the discharge of materials into the environment and other environmental protection issues. The laws and regulations may, among other potential consequences, require that we acquire permits before commencing drilling; restrict the substances that can be released into the environment with drilling and production activities; limit or prohibit drilling activities on protected areas such as wetlands or wilderness areas; require that reclamation measures be taken to prevent pollution from former operations; require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells and remediating contaminated soil and groundwater and require remedial measures be taken with respect to property designated as a contaminated site, for which we are a responsible person.

Under these laws and regulations, we could be liable for personal injury, clean-up costs and other environmental and property damages, as well as administrative, civil and criminal penalties. We maintain limited insurance coverage for sudden and accidental environmental damages as well as environmental damage that occurs over time. However, we do not believe that insurance coverage for the full potential liability of environmental damages is available at a reasonable cost. Accordingly, we could be liable, or could be required to cease production on properties, if environmental damage occurs.

The costs of complying with environmental laws and regulations in the future may harm our business. Furthermore, future changes in environmental laws and regulations could occur that result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, any of which could have a material adverse effect on our financial condition or results of operations.

We compete for oil and gas properties with many other exploration and development companies throughout the world who have access to greater resources.

We operate in a highly competitive environment in which we compete with other exploration and development companies to acquire a limited number of prospective oil and gas properties. Many of our competitors are much larger than we are and, as a result, may enjoy

a competitive advantage in accessing financial, technical and human resources. They may be able to pay more for productive oil and gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial, technical and human resources permit.

Our share ownership is highly concentrated and, as a result, our principal shareholder effectively controls our business.

As at the date of this annual report, our largest shareholder, Robert M. Friedland, owned approximately 27% of our common shares. As a result, he effectively controls our Board of Directors and determines our policies, business and affairs and the outcome of any corporate transaction or other matter, including mergers, consolidations and the sale of all, or substantially all, of our assets.

In addition, the concentration of our ownership may have the effect of delaying, deterring or preventing a change in control that otherwise could result in a premium in the price of our common shares.

If we lose our key management and technical personnel, our business may suffer

We rely upon a relatively small group of key management and technical personnel. Messrs. David Martin and E. Leon Daniel, in particular, have extensive experience in oil and gas operations throughout the world. We do not maintain any key man insurance. We do not have employment agreements with certain of our key management and technical personnel and we cannot assure you that these individuals will remain with us in the future. An unexpected partial or total loss of their services would harm our business.

COMPETITION

The oil and gas industry is highly competitive. Our position in the oil and gas industry, which includes the search for and development of new sources of supply, is particularly competitive. Our competitors include major, intermediate and junior oil and natural gas companies and other individual producers and operators, many of which have substantially greater financial and human resources and more developed and extensive infrastructure than we do. Our larger competitors, by reason of their size and relative financial strength, can more easily access capital markets than we can and may enjoy a competitive advantage in the recruitment of qualified personnel. They may be able to absorb the burden of any changes in laws and regulations in the jurisdictions in which we do business more easily than we can, adversely affecting our competitive position. Our competitors may be able to pay more for productive oil and natural gas properties and may be able to define, evaluate, bid for, and purchase a greater number of properties and prospects than we can. Further, these companies may enjoy technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to acquire additional properties in the future will depend upon our ability to conduct efficient operations, to evaluate and select suitable properties, implement advanced technologies, and to consummate transactions in a highly competitive environment. The oil and gas industry also competes with other industries in supplying energy, fuel and other needs of consumers. See "Risk Factors".

ENVIRONMENTAL REGULATIONS

Our conventional oil and gas, EOR, HTL and GTL operations are subject to various levels of government laws and regulations relating to the protection of the environment in the countries in which they operate. See “Risk Factors”. We believe that our operations comply in all material respects with applicable environmental laws.

In the U.S., environmental laws and regulations, implemented principally by the Environmental Protection Agency, Department of Transportation and the Department of the Interior and comparable state agencies, govern the management of hazardous waste, the discharge of pollutants into the air and into surface and underground waters and the construction of new discharge sources, the manufacture, sale and disposal of chemical substances, and surface and underground mining. These laws and regulations generally provide for civil and criminal penalties and fines, as well as injunctive and remedial relief.

In China, environmental regulation does not exist on a national level. Individual projects are monitored by the state and the standard of environmental regulation depends on each case.

ENVIRONMENTAL PROVISIONS

As at December 31, 2004, a $0.7 million provision has been made for future site restoration and plugging and abandonment of wells in the U.S., which are currently estimated at $1.4 million. We do not make such a provision for our oil and gas operations in China as the remaining life of our Dagang production sharing contract is less than the remaining economic life of the field and there is no obligation on our part to contribute to the future cost to abandon the field and restore the site. During 2004, we recorded a further provision for future site restoration and plugging and abandonment of wells of $0.2 million.

GOVERNMENT REGULATIONS

Our business is subject to certain U.S. and Chinese federal, state and local laws and regulations relating to the exploration for, and development, production and marketing of, crude oil and natural gas, as well as environmental and safety matters. In addition, the Chinese government regulates various aspects of foreign company operations in China. Such laws and regulations have generally become more stringent in recent years in the U.S., often imposing greater liability on a larger number of potentially responsible parties. It is not unreasonable to expect that the same trend will be encountered in China. Because the requirements imposed by such laws and regulations are frequently changed, we are not able to predict the ultimate cost of compliance.

EMPLOYEES

As at December 31, 2004 we had 137 employees. None of our employees are unionized.

Information on our executive officers is presented in Item 10 of this Annual Report on Form 10-K.

RESERVES, PRODUCTION AND RELATED INFORMATION

See the "Supplementary Disclosures About Oil and Gas Production Activities" which follows the notes to our financial statements set forth in Item 8 in this Annual Report on Form 10-K for information with respect to our oil and gas producing activities. We have not filed with nor included in reports to any other U.S. federal authority or agency, any estimates of total proved crude oil or natural gas reserves since the beginning of the last fiscal year.

The following tables set forth, for each of the last three fiscal years, our average sales prices and average operating costs per unit of production based on our net interest after royalties. Average operating costs are for lifting costs only and exclude production taxes, allocated engineering support costs, depletion and depreciation income taxes, interest, selling and administrative expenses.

	Average Sales Price			Average Operating Costs		
	2004	2003	2002	2004	2003	2002
Crude Oil and Natural Gas ($/Boe)						
U.S	$34.66	$25.69	$22.43	$8.94	$7.65	$6.76
China	$36.11	$28.41	$22.30	$6.04	$9.31	$6.49

The following table sets forth the number of commercially productive wells (both producing wells and wells capable of production) in which we held a working interest at the end of each of the last three fiscal years:

	2004		2003		2002	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
U.S.	97(5)	78.9(5)	77	60.4	60(3)	43.9(3)
China	21	10.3(6)	9	7.4	9(4)	7.4(4)

(1) Gross wells are the total number of wells in which an interest is owned.
(2) Net wells are the sum of fractional interests owned in gross wells.
(3) After the sale of 4.4 net (7 gross) Spraberry wells in August 2002 and a 50% working interest, or 6.9 net wells, in our remaining Spraberry wells in October 2002.
(4) After the sale of 3.4 net (4 gross) Daqing wells in January 2002.
(5) After the sale of 0.8 net (2 gross) Sledge Hamar wells in December 2004 and the purchase of 8.2 net (9 gross) Knight's Landing wells partially in April of 2004 and the remainder (including an increase in the working interest of the existing wells) in December of 2004.
(6) After giving effect to the 40% farm-in of CITIC to Dagang field.

The following two tables set forth, for each of the last three fiscal years, our participation in the completed drilling of net oil and gas wells:

Exploratory

	Productive		
	2004	2003	2002
U.S.	3.4	—	—
China	—	—	—
Total	3.4	0	0

	Dry		
	2004	2003	2002
U.S.	5.4	—	1.7(1)
China	—	—	—
Total	5.4	0	1.7

(1) Includes 1.5 (3 gross) net exploratory wells drilled in Kentucky during 2001, which were determined to be dry in 2002.

Development

	Productive		
	2004	2003	2002
U.S.	7.3 (1)	17.0	8.8
China	7.9	—	—
Total	15.2	17.0	8.8

	Dry		
	2004	2003	2002
U.S.	2.0	2.0	-
China	—	—	—
Total	2.0	2.0	0

(1) Includes 0.3 (1 gross) net producing wells acquired as a result of the farm-in to LAK Ranch.

Wells in Progress

At the end of 2004, 2003 and 2002 we had 2.9 (6 gross), 2.8 (5 gross) and 2.3 (5 gross) net wells, respectively, which were either in the process of drilling or suspended.

The following table sets forth our holdings of developed and undeveloped oil and gas acreage as at December 31, 2004:

	Developed		Undeveloped	
	Gross Acres(1)	Net Acres(2)	Gross Acres(1)	Net Acres(2)
U.S.	16,224	8,649	100,315	38,288
China (3)	2,289	1,126	899,760	889,567

(1) Gross acres include the interests of others.
(2) Net acres exclude the interests of others.
(3) The number of developed acres disclosed in respect of our China properties relates only to those portions of the field covered by our producing operations and does not include the remaining portions of the field previously developed by CNPC.

The following table sets out estimates of our share of proved reserves in respect of our U.S. and China operations and calculations of cash flows, before tax and after tax, undiscounted and discounted at 10% and 15%, based on costs and prices as at December 31, 2004. Estimates for our U.S. and China operations were prepared by independent petroleum consultants Netherland, Sewell & Associates Inc. and Gilbert Laustsen Jung Associates Ltd., respectively.

	Our Share		Our Share of Before Tax Cash Flows In Thousands of U.S.Dollars Discounted at:			Our Share of After Tax Cash Flows In Thousands of U.S.Dollars Discounted at:		
	Oil (Mbbl)	Gas (MMcf)	0%	10%	15%	0%	10%	15%
Net Proved Reserves (1)								
U.S.	1,430	2,683	$ 33,427	$ 22,189	$ 19,375	$ 33,427	$ 22,189	$ 19,375
China	7,908	-	184,311	114,637	93,534	139,603	88,829	73,254
	9,338	2,683	$ 217,738	$ 136,826	$ 112,909	$ 173,030	$ 111,018	$ 92,629

(1) "**Net Proved Reserves**" are our share of the estimated quantities of crude oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic conditions. See the "Supplementary Disclosures about Oil and Gas Production Activities", which follow the notes to our financial statements set forth in Item 8 of this Annual Report on Form 10-K.

Special Note to Canadian Investors

Ivanhoe is a United States Securities and Exchange Commission ("**SEC**") registrant and files annual reports on Form 10-K. Accordingly, our reserves estimates and securities regulatory disclosures are prepared based on U.S. disclosure standards. In 2003, certain Canadian securities regulatory authorities adopted *National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**") which prescribes certain standards that Canadian companies are required to follow in the preparation and disclosure of reserves and related information. We applied for, and have been granted, exemptions from certain NI 51-101 disclosure requirements. These exemptions permit us to substitute disclosures based on U.S. standards for much of the annual disclosure required by NI 51-101 and to prepare our reserves estimates and related disclosures in accordance with U.S. disclosure requirements, generally accepted industry practices in the U.S. as promulgated by the Society of Petroleum Engineers, and the standards of the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") modified to reflect U.S. disclosure requirements.

The reserves quantities disclosed in this Annual Report on Form 10-K represent net proved reserves calculated on a constant price basis using the standards contained in SEC Regulation S-X and FAS 69. Such information differs from the corresponding information prepared in accordance with Canadian disclosure standards under NI 51-101. The primary differences between the U.S. requirements and the NI 51-101 requirements are as follows:

- SEC registrants apply SEC reserves definitions and prepare their reserves estimates in accordance with SEC requirements and generally accepted industry practices in the U.S. whereas NI 51-101 requires adherence to the definitions and standards promulgated by the COGE Handbook;
- the SEC mandates disclosure of proved reserves calculated using year-end constant prices and costs only whereas NI 51-101 also requires disclosure of reserves and related future net revenues using forecasted prices;
- the SEC mandates disclosure of proved and proved producing reserves by country only whereas NI 51-101 requires disclosure of more reserve categories and product types;
- the SEC does not require separate disclosure of proved undeveloped reserves or related future development costs whereas NI 51-101 requires disclosure of more information regarding proved undeveloped reserves, related development plans and future development costs; and
- the SEC leaves the engagement of independent qualified reserves evaluators to the discretion of a company's board of directors whereas NI 51-101 requires issuers to engage such evaluators and to file their reports.

The foregoing is a general and non-exhaustive description of the principal differences between U.S. disclosure standards and NI 51-101 requirements.

ITEM 3. LEGAL PROCEEDINGS

We are not currently a party to any material legal proceedings.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matter was submitted to a vote of security holders during the fourth quarter of 2004.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Market Information

Our common shares trade on the NASDAQ SmallCap Market and the Toronto Stock Exchange. The high and low sale prices of our common shares as reported on the NASDAQ and Toronto Stock Exchange for each quarter during the past two years are as follows:

NASDAQ MARKET (IVAN)
(U.S.$)

	2004				2003			
	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr
High	3.20	2.33	3.06	4.28	7.55	3.07	1.18	.60
Low	2.03	1.22	2.08	1.96	2.52	.79	.42	.50

TORONTO STOCK EXCHANGE (IE)
(CDN$)

	2004				2003			
	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr
High	3.90	3.00	4.15	5.49	10.40	4.15	1.60	.88
Low	2.56	1.62	2.88	2.63	3.30	1.10	.53	.77

On December 31, 2004, the closing prices for our common shares were $2.52 on the NASDAQ SmallCap Market and Cdn. $3.04 on the Toronto Stock Exchange.

Exemptions from Certain NASDAQ Marketplace Rules

NASDAQ may provide exemptions from certain of its Marketplace Rules to foreign issuers when those rules are contrary to a law, rule or regulation of any public authority exercising jurisdiction over such issuer or contrary to generally accepted business practices in the issuer's country of domicile.

We have received from NASDAQ an exemption from NASDAQ's requirement that a majority of our Board of Directors be comprised of independent directors. Existing Toronto Stock Exchange guidelines recommend, but do not require, that a majority of the directors of a corporation be "unrelated" directors. An "unrelated" director is a director who is independent of management and is free from any interest and any business or other relationship which could, or could reasonably be perceived to, materially interfere with the director's ability to act with a view to the best interests of the corporation, other than interests and relationships arising from shareholding. Three of the eight directors on our board are "unrelated" for the purposes of the Toronto Stock Exchange guidelines.

We have also received from NASDAQ an exemption from NASDAQ's requirement that our shareholders approve the issuance of more than 20% of our total outstanding common shares in connection with our proposed acquisition of Ensyn and any related private placement transactions, provided that we comply with the rules and policies of the Toronto Stock Exchange. The rules and policies of the Toronto Stock Exchange require us to obtain shareholder approval for the issuance of common shares in connection with the Ensyn transaction and any related private placements if the aggregate number of common shares to be issued exceeds 25% of the common shares outstanding immediately prior to the transaction.

Holders of Common Shares

As at December 31, 2004, a total of 169,664,911 of our common shares were issued and outstanding and held by 180 holders of record with an estimated 45,500 additional shareholders whose shares were held for them in street name or nominee accounts.

Dividends

We have not paid any dividends on our outstanding common shares since we were incorporated and we do not anticipate that we will do so in the foreseeable future. The declaration of dividends on our common shares is, subject to certain statutory restrictions described below, within the discretion of our Board of Directors based on their assessment of, among other factors, our earnings or lack thereof, our capital and operating expenditure requirements and our overall financial condition. Under the *Yukon Business Corporations Act*, our Board of Directors has no discretion to declare or pay a dividend on our common shares if they have reasonable grounds for believing that we are, or after payment of the dividend would be, unable to pay our liabilities as they become due or that the realizable value of our assets would, as a result of the dividend, be less than the aggregate sum of our liabilities and the stated capital of our common shares.

Exchange Controls and Taxation

There is no law or governmental decree or regulation in Canada that restricts the export or import of capital, or affects the remittance of dividends, interest or other payments to a non-resident holder of our common shares, other than withholding tax requirements.

There is no limitation imposed by the laws of Canada, the laws of the Yukon, or our constating documents on the right of a non-resident to hold or vote our common shares, other than as provided in the *Investment Canada Act* (Canada) (the "**Investment Act**"), which generally prohibits a reviewable investment by an entity that is not a "**Canadian**", as defined, unless after review, the minister responsible for the Investment Act is satisfied that the investment is likely to be of net benefit to Canada. An investment in our common shares by a non-Canadian who is not a "**WTO investor**" (which includes governments of, or individuals who are nationals of, member states of the World Trade Organization and corporations and other entities which are controlled by them), at a time when we were not already controlled by a WTO investor, would be reviewable under the Investment Act under two circumstances. First, if it was an investment to acquire control (within the meaning of the Investment Act) and the value of our assets, as determined under Investment Act regulations, was Cdn. $5 million or more. Second, the investment would also be reviewable if an order for review was made by the federal cabinet of the Canadian government on the grounds that the investment related to Canada's cultural heritage or national identity (as prescribed under the Investment Act), regardless of asset value. An investment in our common shares by a WTO investor, or by a non-Canadian at a time when we were already controlled by a WTO investor, would be reviewable under the Investment Act if it was an investment to acquire control and the value of our assets, as determined under Investment Act regulations, was not less than a specified amount, which for 2005 is Cdn.$250 million. The Investment Act provides detailed rules to determine if there has been an acquisition of control. For example, a non-Canadian would acquire control of us for the purposes of the Investment Act if the non-Canadian acquired a majority of our outstanding common shares. The acquisition of less than a majority, but one-third or more, of our common shares would be presumed to be an acquisition of control of us unless it could be established that, on the acquisition, we were not controlled in fact by the acquirer. An acquisition of control for the purposes of the Investment Act could also occur as a result of the acquisition by a non-Canadian of all or substantially all of our assets.

Amounts that we may, in the future, pay or credit, or be deemed to have paid or credited, to you as dividends in respect of the common shares you hold at a time when you are not a resident of Canada within the meaning of the *Income Tax Act* (Canada) will generally be subject to Canadian non-resident withholding tax of 25% of the amount paid or credited, which may be reduced under the Canada-U.S. Income Tax Convention (1980) (the "**Convention**"). Currently, under the Convention, the rate of Canadian non-resident withholding tax on the gross amount of dividends paid or credited to a U.S. resident is generally 15%. However, if the beneficial owner of such dividends is a U.S. resident corporation, which owns 10% or more of our voting stock, the withholding rate is reduced to 5%. In the case of certain tax-exempt entities, which are residents of the U.S. for the purpose of the Convention, the withholding tax on dividends may be reduced to 0%.

Sales of Unregistered Securities

During the year ended December 31, 2004, we issued securities, which were not registered under the Securities Act of 1933 (the "**Act**"), as follows:

- in February 2004, we issued 5,448,276 special warrants at a price of $2.90 per special warrant to two institutional investors in a transaction exempt from registration under Rule 903 of the Act. Each special warrant was exercisable to acquire, for no additional consideration, one common share and one share purchase warrant following the issuance of a receipt for a prospectus by applicable Canadian securities regulatory authorities, which occurred in March 2004. Two common share purchase warrants are exercisable to purchase an additional common share at $3.00 at any time on or prior to the first anniversary date following the special warrant date of issue and at $3.20 thereafter until the second anniversary date of the special warrant date of issue; and
- in March 2004, we issued 1,724,138 special warrants at a price of $2.90 per special warrant to an institutional investor in a transaction exempt from registration under Rule 903 of the Act. Each special warrant was exercisable to acquire, for no additional consideration, one common share and one share purchase warrant following the issuance of a receipt for a prospectus by applicable Canadian securities regulatory authorities, which occurred in March 2004. Two common share purchase warrants are exercisable to purchase an additional common share at $3.00 at any time on or prior to the first anniversary date following the special warrant date of issue and at $3.20 thereafter until the second anniversary date of the special warrant date of issue.

ITEM 6. FIVE YEAR SUMMARY OF SELECTED FINANCIAL DATA

The selected financial data set forth below are derived from the accompanying financial statements, which form part of this Annual Report on Form 10-K. The financial statements have been prepared in accordance with generally accepted accounting principles ("**GAAP**") applicable in Canada, which are not materially different from GAAP in the U.S. except as noted immediately below in "Reconciliation to U.S. GAAP". See also Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations".

The following table shows selected financial information for the years indicated:

	December 31, (stated in thousands of U.S. dollars, except per share amounts)				
	2004	2003	2002	2001	2000
Financial Position					
Total assets	118,486	106,574	107,088	104,003	99,800
Long-term debt	2,639	833	Nil	Nil	Nil
Shareholders' equity	103,586	100,537	100,548	96,897	95,838
Common shares outstanding (in thousands)	169,665	161,359	144,466	139,267	126,874
Capital investments	46,454	15,391	18,828	40,504	40,827
Results of Operations					
Revenues	17,997	9,659	8,437	9,722	14,063(1)
Net income (loss)	(20,725)(2)	(30,179)(2) (3)	(7,130)(2) (3)	(21,122)(2)	5,429
Net income (loss) per share — basic	(0.12)	(0.20)	(0.05)	(0.16)	0.05
Net income (loss) per share — diluted	(0.12)	(0.20)	(0.05)	(0.16)	0.04

(1) Includes $12.2 million gain on sale of our Russian project. See Note 9 to our financial statements under Item 8 in our 2001 Annual Report on Form 10-K.
(2) Includes asset write-downs and provisions for impairment of $16.6 million, $23.3 million, $2.4 million and $14.0 million for 2004, 2003, 2002 and 2001, respectively. See Notes 4 and 13 to our financial statements under Item 8 in this Annual Report on Form 10-K.
(3) Restated by $0.5 million and $0.3 million in 2003 and 2002, respectively, for a change in accounting policy to recognize compensation costs using the fair value based method of accounting for stock options granted to employees and directors after January 1, 2002. See Notes 2 and 9 to our financial statements under Item 8 of this Annual Report on Form 10-K.

Reconciliation to U.S. GAAP

Our financial statements have been prepared in accordance with GAAP applicable in Canada, which differ in certain respects from those principles that we would have followed had our financial statements been prepared in accordance with GAAP in the U.S. The only material differences between Canadian and U.S. GAAP, which affect our financial statements are as follows:

- adjustment for the reduction in stated capital in 1999,
- increase in the ascribed value of shares issued for the acquisition of U.S. royalty interests in 1999 and 2000,
- additional impairment provision for our China oil and gas properties in 2001, net of depletion expense,
- reduction in impairment provision for our U.S. oil and gas properties in 2004, net of depletion expense,
- net additional expense from 2001 to 2004 in connection with development costs for our GTL and EOR projects, and
- reduction in the net losses from 2002 to 2004 for stock based compensation accounted for under the intrinsic value method for U.S. GAAP.

For the U.S. GAAP reconciliations, see Note 19 to our financial statements in this Annual Report on Form 10-K.

Had we followed U.S. GAAP, certain selected financial information reported above, in accordance with Canadian GAAP, would have been reported as follows:

	Year ended December 31, (stated in thousands of U.S. dollars, except per share amounts)				
	2004	2003	2002	2001	2000
Financial Position					
Total assets	105,791	94,024	91,921	90,219	101,158
Shareholders' equity	90,892	87,987	85,279	83,113	97,196
Results of Operations					
Net income (loss)	(19,696)	(27,086)	(8,202)	(36,264)	5,429
Net income (loss) per share — basic	(0.12)	(0.18)	(0.06)	(0.28)	0.05
Net income (loss) per share — diluted	(0.12)	(0.18)	(0.06)	(0.28)	0.05

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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THE FOLLOWING SHOULD BE READ IN CONJUNCTION WITH THE CONSOLIDATED FINANCIAL STATEMENTS INCLUDED IN THIS ANNUAL REPORT ON FORM 10-K. THE CONSOLIDATED FINANCIAL STATEMENTS HAVE BEEN PREPARED IN ACCORDANCE WITH GAAP IN CANADA. THE IMPACT OF SIGNIFICANT DIFFERENCES BETWEEN CANADIAN AND U.S. GAAP ON THE FINANCIAL STATEMENTS IS DISCLOSED IN NOTE 19 TO THE CONSOLIDATED FINANCIAL STATEMENTS.

OUR DISCUSSION AND ANALYSIS OF OUR OIL AND GAS ACTIVITIES WITH RESPECT TO OIL AND GAS VOLUMES, RESERVES AND RELATED PERFORMANCE MEASURES IS PRESENTED ON OUR WORKING INTEREST BASIS AFTER ROYALTIES.

NOTE: CANADIAN INVESTORS SHOULD READ THE SPECIAL NOTE TO CANADIAN INVESTORS ON PAGE 22 WHICH HIGHLIGHTS DIFFERENCES BETWEEN OUR RESERVE ESTIMATES AND RELATED DISCLOSURES THAT ARE OTHERWISE REQUIRED BY CANADIAN REGULATORY AUTHORITIES.

Executive Overview of 2004 Results

Although our 2004 results improved over those achieved a year ago, we were not profitable in 2004. Revenue for 2004 increased by 86% to $18.0 million on the strength of an increase in production as well as higher oil and gas prices. However, this improvement was offset by increased costs related to our significant business development activities, a $16.3 million impairment of a number of our unproved and proved U.S. oil and gas properties and professional fees related to our assessment of the effectiveness of the design and operation of our internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002. Despite cost increases, we achieved positive cash flow from operations of $4.0 million for the year ended December 31, 2004 compared to deficits of $1.5 million and $2.1 million for the comparable periods in 2003 and 2002, respectively.

Our single goal continues to be to build our oil and gas reserve base and production. Our strategy is to do this through the application of technologically innovative methods for oil and gas recovery. Our most significant activity in this regard, during 2004, is related to our December 2004 agreement to acquire Ensyn and its proprietary RTP™ Technology. We believe that the deployment of this RTP™ Technology can launch us into the forefront of heavy oil production around the world.

The following table sets forth certain selected consolidated data for the past three years:

	Year ended December 31, (stated in thousands of U.S. dollars, except share amounts)		
	2004	2003	2002
Net loss	20,725	30,179	7,130
Net loss per share	0.12	0.20	0.05
Average annual production (Mboe/d)	1,376	979	1,020
Capital investments	46,454	15,391	18,828
Cash flow (deficit) from operating activities	4,032	(1,522)	(2,120)

Financial Results - Year to Year Change in Net Loss

The following provides an analysis of our changes in net losses for the year ended December 31, 2004 when compared to the same period for 2003 and for the year ended December 31, 2003 when compared to the same period for 2002:

	2004 vs. 2003	2003 vs 2002
	(stated in thousands of U.S. Dollars)	
Net Losses for 2003 and 2002, as restated	$ 30,179	$ 7,130
Favorable (unfavorable) variances:		
Cash Items:		
Net Operating Revenues:		
Production volumes	4,534	(416)
Oil and gas prices	3,442	1,899
Hedge loss	250	(243)
Less: Operating costs	(780)	(452)
	7,446	788
General and administrative	(177)	(2,091)
Net interest	(36)	(179)
Total Cash Variances	7,233	(1,482)
Non-Cash Items:		
Depletion and depreciation	(3,653)	(517)
Stock based compensation	(800)	(165)
Write downs of GTL investments	3,071	(885)
Impairment of U.S. oil and gas properties	3,650	(20,000)
Other	(47)	-
Total Non-Cash Variances	2,221	(21,567)
Net Losses for 2004 and 2003	$ 20,725	$ 30,179

Our net loss for 2004 was $20.7 million ($0.12 per share) compared to our net loss in 2003 of $30.2 million ($0.20 per share) after restatement of 2003 for a retroactive change in accounting policy for stock based compensation (See Notes 2 and 9). The decrease in our net loss from 2003 to 2004 of $9.5 million is due mainly to a $3.7 million reduction in impairment of our U.S. oil and gas properties, $3.1 million decrease in write-downs of our GTL investments and a $7.4 million increase in net operating revenues. This is partially offset by a $3.7 million increase in depletion and depreciation expense and a $1.0 million increase in general administrative expenses including stock based compensation.

The $23.0 million increase in our restated net losses from 2002 to 2003 is due mainly to a $20.0 million impairment of our U.S. oil and gas properties, a $0.9 million increase in write-downs of our GTL investments, a $0.5 million increase in depletion and depreciation expense and a $2.3 million increase in general and administrative costs including stock based compensation. This is partially offset by an increase in net operating revenues of $0.8 million, including a $0.2 million hedge loss for 2003.

Significant variances in our net losses are explained in the sections that follow.

<u>**Net Operating Revenues**</u>

- **Production Volumes 2004 vs. 2003**

Net production volumes in 2004 increased 41% from 2003 due to 63% and 26% increases in production volumes in our China and U.S. properties, respectively, resulting in increased revenues of $4.5 million.

Net production volumes at the Dagang field increased 46% in 2004 despite the farm-out of 40% of our interest to Richfirst in June 2004. We commenced development of the Dagang field in late 2003 and by the end of 2004 we drilled 19 wells of which 16 were completed and placed on production. The year-end 2004 gross production rate was 1,655 Bopd (774 net Bopd) compared to 505 Bopd at the end of 2003 (236 net Bopd adjusting for a 40% Richfirst farm-in for comparability to 2004). At year-end 2004, a total of 22 wells were producing at our Dagang field. Additionally, we continue to benefit from the expanded Daqing development program and the royalty interest we retained after the sale of our working interest in this field in 2002 as our royalty share of production increased 224% from 2003.

Net production volumes in the U.S. increased 26% mainly from the Citrus and Knights Landing fields, both of which started production in 2004, and our continuing development program at South Midway. We farmed into the Knights Landing gas field in northern California in February 2004 with a 50% working interest in 4 producing natural gas wells and in December 2004 improved the potential of our California properties by increasing our working interest to between 80% and 100% in 12 Knights Landing natural gas wells capable of production and selling our interest in the Sledge Hamar field. We are the operator of the Citrus field and currently have a 100% working interest before payout in three Citrus wells, which were completed and placed on production in 2004. We continue to see increased production rates from our successful drilling and steaming operations at our South Midway field where we have drilled 19 producing wells over the last two years. At year end 2004, we were producing from 95 wells in the South Midway, Spraberry, Citrus, and Knights Landing fields at gross rates of production of approximately 1,320 Boe/d (920 net Boe/d).

The following is a comparison of changes in production volumes for the year ended December 31, 2004 when compared to the same period in 2003:

	Average Net Boe's		Percentage
	2004	2003	Change
China:			
Dagang	190,309	130,651	46%
Daqing	44,626	13,771	224%
	234,935	144,422	63%
U.S.:			
South Midway	183,875	169,858	8%
Citrus	31,008	-	100%
Knights Landing	14,786	-	100%
Others	38,945	42,962	-9%
	268,614	212,820	26%
	503,549	357,242	41%

- **Production Volumes 2003 vs. 2002**

Net production volumes in 2003 declined 4% from 2002 due mainly to the sale of our interests in certain wells in the Spraberry field in the last half of 2002 and in Dagang due to a combination of factors which occurred during 2003 including well workovers, natural declines and the suspension of one pilot phase well pending conversion to water injection service. Production from South Midway increased 24% in 2003 primarily due to drilling 15 new wells in the southern expansion in 2003 and initiation of full-scale cyclic steam enhancement program in May 2002 in the primary area of South Midway and cyclic steaming of the southern expansion wells in the fourth quarter of 2003.

At year-end 2003, we were producing from seven pilot phase wells in the Dagang field at gross rates of 505 Bopd (236 net Bopd adjusting for a 40% Richfirst farm-in for comparability to 2004) compared to 599 Bopd at the end of 2002 (280 net Bopd adjusting for a 40% Richfirst farm-in for comparability to 2004) and 76 wells from the South Midway and Spraberry fields at gross rates of production of approximately 911 Boe/d (611 net Boe/d).

The following is a comparison of changes in production volumes for the year ended December 31, 2003 when compared to the same period in 2002:

	Average Net Boe's		Percentage
	2003	2002	Change
China:			
Dagang	130,651	141,257	-8%
Daqing	13,771	3,591	283%
	144,422	144,848	0%
U.S.:			
South Midway	169,858	136,705	24%
Spraberry	40,695	88,598	-54%
Others	2,266	1,998	13%
	212,820	227,301	-6%
	357,242	372,149	-4%

- **Oil and Gas Prices 2004 vs. 2003**

Oil and gas prices increased 32% per Boe in 2004 generating $3.4 million in additional revenue as compared to 2003. We realized an average of $36.11/Boe from our operations in China during 2004, which is an increase of $7.70/Boe from 2003 prices and accounts for $1.7 million of our increase in revenues. From the U.S. operations, we realized an average of $34.66/Boe during 2004, which is an increase of $8.97/Boe and accounts for $1.7 million of our increased revenues.

We entered into costless collar derivatives to hedge our cash flow from the sale of 500 barrels of oil production per day over two six-month periods starting October 2002 and June 2003. We realized losses of $0.3 million on these derivative transactions in 2003 but had no derivative contracts in place during 2004.

- **Oil and Gas Prices 2003 vs. 2002**

Oil and gas prices increased 20% per Boe in 2003 generating $1.9 million in additional revenue as compared to 2002. We realized an average of $28.41/Boe from our operations in China during 2003, which is an increase of $6.11/Boe from 2002 prices and accounts for $0.9 million of our increase in revenues. From the U.S. operations, we realized an average of $25.69/Boe during 2003, which is an increase of $3.26/Boe and accounts for $1.0 million of our increased revenues.

As discussed above, we realized losses of $0.3 million on derivative transactions in 2003 compared to the insignificant losses realized on such transactions during 2002.

- **Operating Costs 2004 vs. 2003**

Operating costs for 2004 increased $0.8 million in absolute terms from 2003 but decreased $1.96 on a per barrel of oil equivalent basis.

Operating costs in China, including engineering support, decreased 41% or $5.57 per Boe for 2004 due mainly to an increase in production from the Dagang field in relation to the level of fixed field operating costs and engineering support required to operate the

field and reduced well workover and power costs during 2004.

Operating costs in the U.S., including engineering support and production taxes, increased 8% or $0.89 per Boe for 2004. Field operating costs increased $1.29/Boe due mainly to an increase in fuel costs incurred for the cyclic steam operations in the southern expansion of South Midway, increased costs to treat hydrogen sulfide levels in the gas produced from the South Midway field and the start up of production operations at our Citrus, Knights Landing, and Sledge Hamar fields. This is partially offset by a reduction in workover costs at our South Midway and Spraberry fields from 2003. Engineering support increased $0.19/Boe due mainly to the start up of production operations at Citrus, where we are the operator, and also at Knights Landing where we became the operator in December 2004. Production taxes are down $0.59/Boe due mainly to a retroactive reassessment of property values at South Midway, which led to a refund of prior ad valorem taxes paid and a reduction in current assessed values.

- **Operating Costs 2003 vs. 2002**

Operating costs for 2003 increased $0.5 million in absolute terms from 2002 and $1.70 on a per barrel of oil equivalent basis.

Operating costs in China, including engineering support, increased 33% or $3.42 per Boe in 2003 mainly due to increased well workover and manpower costs in preparation for the full field development which started in the fourth quarter of 2003.

Operating costs in the U.S., including engineering support and production taxes, increased 5% or $0.52 per Boe in 2003 due mainly to an increase in fuel costs incurred for the cyclic steam operations in the southern expansion of South Midway partially offset by a reduction in field operating costs at the Spraberry field as the wells mature.

Production and operating information including oil and gas revenue, operating costs and depletion, on a per Boe basis, from 2002 to 2004 are detailed below:

	Year ended December 31,								
	2004			2003			2002		
	U.S.	China	Total	U.S.	China	Total	U.S.	China	Total
Net Production:									
Boe	268,614	234,935	503,549	212,820	144,422	357,242	227,301	144,848	372,149
Boe/day for the year	734	642	1,376	583	396	979	623	397	1,020
		Per Boe			Per Boe			Per Boe	
Oil and gas revenue	$ 34.66	$ 36.11	$ 35.34	$ 25.69	$ 28.41	$ 26.79	$ 22.43	$ 22.30	$ 22.38
Operating costs	8.94	6.04	7.59	7.65	9.31	8.52	6.76	6.49	6.66
Production taxes	0.44	-	0.23	1.03	-	0.62	1.21	-	0.74
Engineering support	2.38	2.10	2.25	2.19	4.40	2.89	2.38	3.80	2.93
	11.76	8.14	10.07	10.87	13.71	12.03	10.35	10.29	10.33
Net operating revenue	22.90	27.97	25.27	14.82	14.70	14.76	12.08	12.01	12.05
Depletion	16.80	12.18	14.64	10.58	10.23	10.44	8.39	8.30	8.35
	$ 6.10	$ 15.79	$ 10.63	$ 4.24	$ 4.47	$ 4.32	$ 3.69	$ 3.71	$ 3.70

General and Administration

Our changes in general and administrative expenses for the year ended December 31, 2004 when compared to the same period for 2003 and for the year ended December 31, 2003 when compared to the same period for 2002 were as follows:

	2004 vs. 2003	2003 vs 2002
Favorable (unfavorable) variances:		
General and administrative	$ (177)	$ (2,091)
Stock based compensation	(800)	(165)
	$ (977)	$ (2,256)

As discussed below in this Item 7 in "Critical Accounting Principles and Estimates - Write-down of Non-Oil and Gas Properties", we incur various costs in the pursuit of GTL and EOR projects. Such costs incurred prior to signing an MOU, or similar agreement, are considered to be business development or project identification, are expensed as incurred and are reflected in the following table as GTL or EOR general and administrative expenses. Additionally, we capitalize a portion of our general and administrative costs that can be directly related to, and is necessary to, our capital investment activities. For the years ended December 31, 2004, 2003 and 2002, general and administrative expenses related directly to oil and gas acquisition, exploration and development activities, and

investments in GTL and EOR projects of $3.8 million, $1.8 million and $2.6 million, respectively, were capitalized and thus are not included in the following table of changes in general administrative expenses (including stock based compensation) by segment:

	2004 vs. 2003	2003 vs 2002
Favorable (unfavorable) variances:		
Oil and Gas Activities:		
U.S.	$ 1,119	$ (931)
China	216	(271)
GTL	(140)	(656)
EOR	(442)	-
Corporate	(1,730)	(398)
	$ (977)	$ (2,256)

- **General and Administrative 2004 vs. 2003**

General and administrative expenses related to U.S. operations, before allocations to capital and operating costs, increased $0.8 million for 2004 primarily due to increased labor costs, including non-cash stock based compensation. This is offset by increased allocations of general and administrative to capital investments and operating costs of $1.5 million and $0.4 million, respectively, as a result of increased levels of exploration and development activities in the U.S during 2004 and the start up of production operations at Citrus, where we are the operator, and also at Knights Landing where we became the operator in December 2004.

General and administrative expenses related to the China operations, before allocations of costs to capital and operating costs, increased $0.4 million primarily due to increased labor costs and ramp up of administrative offices required to support the development and exploration activities initiated at the end of 2003. This is offset by increased allocations of general and administrative costs to capital investments and operating costs of $0.5 million and $0.1 million, respectively, primarily as a result of the development program and increased operations at our Dagang field.

We incurred a higher level of business development costs during 2004 related to identification of new opportunities for our GTL and HTL technologies particularly in the Middle East and China resulting in increased general and administrative costs of $0.6 million.

Corporate general and administrative expenses increased $1.7 million mainly due to $0.8 million incurred during 2004 to comply with the provisions of Section 404 of the Sarbanes-Oxley Act of 2002, a $0.8 million increase in non-cash stock based compensation related to the issuance of stock options and other net increases such as higher costs for directors and officers liability insurance.

- **General and Administrative 2003 vs. 2002**

General and administrative costs, including stock based compensation costs, increased $2.3 million in 2003 from 2002.

General and administrative expenses related to U.S. operations increased $0.9 million compared to 2002. General and administrative expenses before allocations of costs to capital investments and operating costs increased $0.3 million for 2003 primarily due to increased labor costs including non-cash stock based compensation. Additionally, allocations of general and administrative costs to capital investments decreased $0.6 million as a result of decreased levels of exploration and development activities in the U.S during 2003.

General and administrative expenses related to the China operations, before allocations of costs to capital investments and operating costs, increased $0.3 million primarily due to costs incurred to explore the possibility of a public listing for Sunwing.

We incurred a higher level of business development costs for our GTL initiatives during 2003 primarily related to pursuing new sources of project financing resulting in increased general and administrative costs of $0.7 million.

Corporate general and administrative expenses increased $0.4 million during 2003 mainly due to fees incurred for the filing of a $100 million Canadian base shelf prospectus and corresponding U.S. shelf registration statement and increase in insurance costs.

Depletion and Depreciation

The primary expense in this classification is depletion of the carrying values of our oil and gas properties in our U.S. and China cost centers over the life of their proved oil and gas reserves as determined by independent reserve evaluators. For more information on how we calculate depletion and determine our proved reserves see “Critical Accounting Principles and Estimates – Oil and Gas Reserves and Depletion” in this Item 7.

- **Depletion and Depreciation 2004 vs. 2003**

Depletion and depreciation increased $3.7 million in 2004, which was due to the increase in depletion rates to $14.64 per Boe in 2004 compared to $10.44 per Boe in 2003.

The U.S. depletion rate for 2004 was $16.80 per Boe, a 59% increase from 2003. Despite a $16.3 million impairment of our U.S. oil and gas properties in 2004, our depletion rate increased in 2004 primarily as a result of significant costs of finding and acquiring proved reserves at our Knights Landing and Citrus fields as measured as at December 31, 2004. We believe we can continue to develop these fields over the coming year in order to economically increase our reserve base and improve our operating results.

The China depletion rate for 2004 was $12.18 per Boe, a 19% increase from 2003, due mainly to a downward revision of our share of proved reserves at Dagang as a result of continued increases in oil prices from 2003 and additional anticipated increases in future development costs. During periods of increasing oil prices our share of proved oil reserves decreases, as fewer barrels of oil are required to recover our costs under our production-sharing contract with CNPC.

- **Depletion and Depreciation 2003 vs. 2002**

Depletion and depreciation increased $0.5 million in 2003, which was primarily due to the increase in depletion rates to $10.44 per Boe in 2003 compared to $8.35 per Boe in 2002.

The U.S. depletion rate for 2003 was $10.58 per Boe, a 26% increase from 2002, due mainly to an increase in the carrying value of our evaluated U.S. oil and gas properties primarily in Northwest Lost Hills, East Texas and North South Forty in the fourth quarter of 2003.

The China depletion rate for 2003 was $10.23 per Boe, a 23% increase from 2002, as a result of a downward revision of our share of proved reserves at Dagang due to increased oil prices in 2003 and anticipated increases in Dagang future development costs.

Write-Down of GTL Investments

As discussed below in this Item 7 in "Critical Accounting Principles and Estimates - Write-down of Non-Oil and Gas Properties", for Canadian GAAP we capitalize technical and commercial feasibility costs incurred for GTL or EOR projects, including studies for the marketability of the projects' products, subsequent to executing an MOU. If no definitive agreement is reached, then the capitalized costs, which are deemed to have no future value, are written down to our results of operations with a corresponding reduction in our investments in GTL and EOR assets. For U.S. GAAP, all such costs are expensed as incurred.

- **Write-Down of GTL Investments 2004 vs. 2003**

In the second quarter of 2004, we wrote down our $0.3 million investment in the Oman GTL project as our opportunity to build a 45,000-barrels per day GTL fuels plant in Oman failed to materialize due to a lack of sufficient uncommitted gas volumes. This compares to the $3.3 million write-down of our GTL investments in connection with negotiation costs incurred to construct and operate a GTL production facility in Qatar, which was terminated in 2003 without reaching a definitive agreement.

- **Write-Down of GTL Investments 2003 vs. 2002**

We wrote-down $3.3 million of our GTL investments in 2003 as a result of the termination of our contract negotiation for a GTL development and production contract in Qatar compared to a write-down of $2.4 million in 2002 related to our investment in Syntroleum's Sweetwater GTL project.

Impairment of U.S. Oil and Gas Properties

As discussed below in this Item 7 in "Critical Accounting Principles and Estimates - Impairment of Proved Oil and Gas Properties", we evaluate each of our cost center's proved oil and gas properties for impairment on a quarterly basis. If as a result of this evaluation, a cost center's carrying value exceeds its expected future net cash flows from its proved and probable reserves then a provision for impairment must be recognized in the results of operations.

- **Impairment of U.S. Oil and Gas Properties 2004 vs. 2003**

We impaired our U.S. oil and gas properties by $16.3 million in 2004, compared to an impairment of $20.0 million in 2003. The

impairment for 2004 is due to an evaluation of a number of our proved properties at the Knights Landing, Citrus and South Midway fields, and a further impairment of our unproved properties, primarily Northwest Lost Hills.

At the Knights Landing gas field, our 2004 drilling resulted in three successful completions and six dry holes. We plan to use 3-D seismic to improve the discovery rate in this field and well workovers are planned to increase gas rates and reduce operating costs. At our Citrus field we are evaluating drilling another horizontal leg in our horizontal well by the second quarter of 2005 to target the upper Antelope zone located a few hundred feet above the existing horizontal well. In the southern expansion area at South Midway, we have supplemented the cyclic steam project with a pilot to test continuous steam injection into two wells. The project began in October 2004 and by year-end 2004 was beginning to yield increased production in the surrounding wells. The further impairment of our Northwest Lost Hills prospect reflects the potential farm-out of a portion of our working interest to one or more partners to fund a test of the well.

- **Impairment of U.S. Oil and Gas Properties 2003 vs. 2002**

The $20.0 million impairment for 2003 was due to an increase in the carrying value of our proved U.S. oil and gas properties primarily in Northwest Lost Hills, East Texas and North South Forty when compared to the expected future cash flows of our U.S. proved reserves at year end 2003. Such carrying values increased as a result of our decision, in the fourth quarter of 2003, to potentially farm-out up to 50% of our working interest to one or more partners to fund a test of Northwest Lost Hills # 1-22. Additionally during 2003, we completed our evaluation of significant portions of our acreage positions in East Texas and North South Forty and either relinquished or plan to relinquish our interests, thus adding to the carrying value of our proved U.S. oil and gas properties.

Capital Investments - 2004

Our investments in capital activities in each of the three most recently completed financial years were as follows:

	Year ended December 31,		
	2004	2003	2002
Oil and Gas Activities:			
U.S.	$ 17,428	$ 8,386	$ 13,305
China	26,965	6,213	3,626
GTL	95	792	1,897
EOR	1,966	-	-
	$ 46,454	$ 15,391	$ 18,828

Oil and Gas Activities - U.S.

We completed the drilling of the first Citrus well, which was spud in December 2003, and drilled two additional Citrus wells and completed production facilities during 2004 for $5.5 million.

We spent $7.1 million on our Knights Landing field during 2004. We farmed-in to the Knights Landing field in February 2004 by purchasing a 50% working interest in four previous discoveries in the contract area and funding gas gathering, surface treatment facilities and meters to connect the four wells to an existing pipeline system. Additionally, we drilled nine new exploratory wells to earn a 50% working interest after payout in any new discoveries, which resulted in three successful completions and six dry holes. In December 2004, we reached an agreement with the operator of the field to purchase its interest in the field, increasing our working interests in the field and 11 existing producing natural gas wells to between 80% and 100%.

We invested $2.1 million during 2004 to extend the SAGD pilot program at LAK Ranch including modifications to the existing facilities for cyclic steaming operations to enable steam injection in the producing horizontal well, installation of fiber optic temperature recording and artificial lift equipment on the producing horizontal well and acquisition of ultra high resolution 3-D seismic needed to better define the optimum reservoir development locations.

In 2004, we drilled seven new wells on the South Midway properties for $1.1 million, consisting of six step-out development locations and one exploratory well. Four of the six development wells were completed as producers. The exploratory well was unsuccessful and will be held for a future disposal well.

We completed the drilling of the first Sledge Hamar well, which was spud in December 2003, and drilled one follow up well for $0.4 million. However, the follow up well drilled in April 2004 encountered the Stevens sands below the oil/water contact and tested only water. After evaluating the production results and other potential hydrocarbon intervals, we concluded that the future economic potential was unfavorable and, in December 2004, sold our working interest for $0.5 million.

We drilled one well at the McCloud River prospect during 2004 for $0.3 million, including prospect acquisition costs. The initial well resulted in a dry hole.

We incurred $0.9 million of lease acquisition costs, including lease rentals, geological and geophysical and seismic on various prospects primarily in California during 2004, which were capitalized under the full cost method of accounting. See "Critical Accounting Principles and Estimates – Full Cost Accounting" in this Item 7.

Oil and Gas Activities - China

We incurred $20.0 million in capital investments during 2004 to further our overall development program at Dagang. We drilled and completed 16 development wells and converted 1 existing well to water injection service. Three new wells were awaiting completion at the end of 2004 and we commenced the drilling of 1 well in late December 2004.

We incurred $7.0 million during 2004 to complete the acquisition, processing and interpretation of approximately 540 miles of a 700-mile seismic acquisition program on the Zitong block. We selected the location of our first exploration well and signed a drilling contract to commence drilling of the well in the first quarter of 2005. The drilling of a second well, expected in late 2005, will follow completion of the remaining portion of our seismic acquisition program.

EOR Activities

Capital investments in EOR related activities for 2004 was $2.0 million, primarily related to Iraqi EOR project activities.

In October 2004, we signed an MOU with the Ministry of Oil of the Government of Iraq to study and evaluate the shallow Qaiyarah oil field in Iraq. The field's reservoirs contain a large proven accumulation of 17.1° API heavy oil at a depth of about 1,000 feet. We will evaluate the potential response of the Qaiyarah oil field to the latest in EOR techniques, along with the potential value that could be added using the Ensyn RTP™ Technology to produce higher quality, more valuable crude oil. The work will include an assessment of the oil-in-place in the reservoirs, and the optimum EOR/HTL methods to establish economically recoverable volumes at the Qaiyarah oil field. If the evaluation studies indicate development of the field is economically viable, we will present a development plan and offer a commercial proposal to implement an EOR program for the Qaiyarah oil field. The Iraqi Ministry of Oil is under no obligation to execute the project or to enter into formal commercial negotiations at the completion of our study.

GTL Activities

There was minimal capital investment in GTL projects for 2004. There were no significant changes in the status of our active GTL projects in Egypt and Bolivia and we continue to pursue definitive agreements for the construction and operation of GTL facilities in those countries.

Liquidity and Capital Resources

Sources and Uses of Cash

Our net cash and cash equivalents decreased by $5.2 million in 2004. Our 2004 operating activities provided $4.0 million in cash due to a 41% increase in our production volumes, primarily from China, and a 32% increase in oil and gas prices from 2003. We raised a net of $22.2 million from two special warrant financings in the first quarter of 2004 and from the exercise of options during the year. We raised $14.0 million of cash during 2004 from the farm-out of a 40% working interest in the Dagang field and the sale of our working interest in the Sledge Hamar field. We completed the drawdown of our non-revolving line of credit for the development of the South Midway field by borrowing $4.0 million and we made note payments of $0.7 million during 2004. This was offset by capital investments, after changes in non-cash working capital, of $43.2 million, as discussed in this Item 7 "Capital Investments – 2004", and $2.5 million to acquire a 15% equity interest in EPIL plus merger expenses of $2.5 million incurred during 2004 to acquire 100% of Ensyn.

Our net cash and cash equivalents increased by $10.5 million in 2003 compared to a decrease of $5.7 million in 2002. We raised $17.9 million more in 2003 than in 2002 through private placements and the exercise of warrants and incentive stock options and we invested $3.4 million less in 2003 than in 2002 on exploration, development and GTL activities. This was partially offset by a reduction in cash generated from asset sales as we sold non-core assets in China and Texas for $5.4 million in 2002.

	Year ended December 31,		
	2004	2003	2002
Cash flow (deficit) from operating activities	$ 4,032	$ (1,522)	$ (2,120)
Investing Activities			
Capital investments, after changes in non-cash working capital	(43,190)	(15,928)	(19,466)
Proceeds from sale of assets	13,958	-	5,351
Investment in Ensyn	(5,016)	(500)	-
Other	(410)	(37)	(65)
	(34,658)	(16,465)	(14,180)
Financing Activities			
Private placements, net of share issue costs	20,428	24,070	9,964
Proceeds from exercise of options and warrants	1,723	3,928	119
Net debt financing	3,306	500	500
	25,457	28,498	10,583
Net Sources (Uses) of Cash	$ (5,169)	$ 10,511	$ (5,717)

Outlook for 2005

Our capital investment budget for 2005 is $79.0 million. Of the total 2005 investment program, $54.2 million, or 69%, is for continued development of our producing fields at Dagang, South Midway, Knights Landing and Citrus. Approximately $22.5 million, or 29% of the budget, is for exploration programs in the U.S., principally in California, and for our exploration commitment in the Zitong block. The balance of our 2005 budget, or approximately $2.3 million, is for the continued development of EOR and GTL initiatives around the world. Additionally, we have agreed to pay $10.0 million in cash and $75 million in stock to acquire Ensyn and expect to incur approximately $1.5 million in Merger related expenses during 2005 in order to close the transaction. We plan to seek financing on an as needed basis, from equity markets, project lenders, joint ventures or other potential financing sources to complete this capital program and acquisition of Ensyn, to pursue acquisitions of proven and probable reserves and to deploy our HTL and GTL technologies. In addition, we, together with our 40% partner in the Dagang project, are in active discussions with European and Chinese lending banks to provide funding for the development of the Dagang field.

In October 2003, we filed a base shelf prospectus with Canadian securities regulatory authorities and a shelf registration statement with the U.S. Securities and Exchange Commission to qualify for potential future sale in Canada and the U.S. up to $100 million of various types of securities, including common shares, preferred shares, warrants and debt securities. These shelf filings are expected to give us greater flexibility to fund our expansion and capital programs and will allow us to take advantage of a broader range of financing opportunities on a timelier basis. A combination of such equity financing, as well as convertible debenture, debt and mezzanine financing and joint venture partner participation, will be required to complete our future capital programs. We cannot assure you that we will be successful in raising the additional funds necessary or securing joint venture partners to complete our capital programs. If we are unsuccessful, we will have to prioritize our capital programs, which may result in delaying and potentially losing some valuable business opportunities.

Contractual Obligations and Commitments

The table below summarizes and cross-references the contractual obligations and commitments that are reflected in our Consolidated Balance Sheets and/or disclosed in the accompanying Notes

	Payments Due by Year (stated in thousands of U.S. dollars)					
	Total	2005	2006	2007	2008	After 2008
Purchase Agreement:	$ 200	$ 100	$ 100	$ -	$ -	$ -
Consolidated Balance Sheets:						
Note payable – current portion *(Note 8)*	1,667	1,667	-	-	-	-
Long term debt *(Note 8)*	2,639	-	1,667	972	-	-
Other Commitments:						-
Interest payable (1)	302	186	99	17	-	-
Lease commitments *(Note 17)*	2,123	616	543	342	287	335
Zitong exploration commitment *(Note 17)*	12,400	12,400	-	-	-	-
Total	$ 19,331	$ 14,969	$ 2,409	$ 1,331	$ 287	$ 335

(1) This is the estimated future interest payments on our note payable and long term debt using the rate of interest in effect as at December 31, 2004, which is 5.25%.

We have excluded our normal purchase arrangements as they are discretionary and/or being performed under contracts which are cancelable immediately or with a 30-day notification period.

Critical Accounting Principles and Estimates

Our accounting principles are described in Note 2 to Notes to the Consolidated Financial Statements in Item 8 of this Annual Report on Form 10-K. We prepare our Consolidated Financial Statements in conformity with GAAP in Canada, which conform in all material respects to U.S. GAAP except for those items disclosed in Note 19 to Notes to the Consolidated Financial Statements in Item 8 of this Annual Report on Form 10-K. For U.S. readers, we have detailed the differences and have also provided a reconciliation of the differences between U.S. and Canadian GAAP in Note 19 to Notes to the Consolidated Financial Statements.

The preparation of our financial statements requires us to make estimates and judgments that affect our reported amounts of assets, liabilities, revenue and expenses. On an ongoing basis we evaluate our estimates, including those related to asset impairment, revenue recognition, allowance for doubtful accounts and contingencies and litigation. These estimates are based on information that is currently available to us and on various other assumptions that we believe to be reasonable under the circumstances. Actual results could vary from those estimates under different assumptions and conditions.

We have identified the following critical accounting policies that affect the more significant judgments and estimates used in preparation of our consolidated financial statements.

Full Cost Accounting — We follow the full cost method of accounting for our oil and gas properties. Under the full cost method, all exploration and development costs associated with lease and royalty interest acquisition, geological and geophysical activities, carrying charges for unproved properties, drilling both successful and unsuccessful wells, gathering and production facilities and equipment, financing, administrative costs directly related to capital projects and asset retirement costs are capitalized on a country-by-country cost center basis. As at December 31, 2004, the carrying values of our U.S. and China cost centers were $40.8 million and $39.7 million, respectively.

The other generally accepted method of accounting for costs incurred for oil and gas properties is the successful efforts method. Under this method, costs associated with land acquisition and geological and geophysical activities are expensed in the year incurred and the costs of drilling unsuccessful wells are expensed upon abandonment.

As a consequence of following the full cost method of accounting, we may be more exposed to potential impairments if the carrying value of a cost center's oil and gas properties exceeds its estimated future net cash flows than if we followed the successful efforts method of accounting. An impairment may occur if a cost center's recoverable reserve estimates decrease, oil and natural gas prices decline or capital, operating and income taxes increase to levels that would significantly affect its estimated future net cash flows. See "Impairment of Proved Oil and Gas Properties" below.

Oil and Gas Reserves — The process of estimating quantities of reserves is inherently uncertain and complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. Our reserve estimates are based on current production forecasts, prices and economic conditions. The reserve numbers and values included in this Annual Report on Form 10-K are only estimates and you should not assume that the present value of our future net cash flows from these estimates is the current market value of our estimated proved oil and gas reserves. (See "Risk Factors")

Reserve estimates are critical to many accounting estimates and financial decisions including:

- determining whether or not an exploratory well has found economically producible reserves. Such determinations involve the commitment of additional capital to develop the field based on current estimates of production forecasts, prices and other economic conditions.

- calculating our unit-of-production depletion rates. Proved reserves are used to determine rates that are applied to each unit-of-production in calculating our depletion expense. In 2004, oil and gas depletion of $7.4 million was recorded in depletion and depreciation expense. If our reserve estimates changed by 10%, our depletion and depreciation expense for 2004 would have changed by approximately $0.7 million assuming no other changes to our reserve profile. See "Depletion" below.

- assessing our proved oil and gas properties for impairment on a quarterly basis. Estimated future net cash flows used to assess impairment of our oil and gas properties are determined using proved and probable reserves [1]. See "Impairment of Proved Oil and Gas Properties" below.

Management is responsible for estimating the quantities of proved oil and natural gas reserves and preparing related disclosures. Estimates and related disclosures are prepared in accordance with SEC requirements, generally accepted industry practices in the U.S. as promulgated by the Society of Petroleum Engineers, and the standards of the COGE Handbook modified to reflect SEC requirements.

Independent qualified reserves evaluators prepare reserve estimates for each property at least annually and issue a report thereon. The reserve estimates are reviewed by our engineers familiar with the property and by our operational management. Our CEO and CFO meet with our operational personnel to review the current reserve estimates and related disclosures in this Annual Report on Form 10-K and upon their review and approval present the independent qualified reserves evaluators' reserve reports to our Board of Directors with a recommendation for approval. Our Board of Directors has approved the reserve estimates and related disclosures in this Annual Report on Form 10-K.

The estimated discounted future net cash flows from estimated proved reserves included in the Supplementary Financial Information in this Annual Report on Form 10-K are based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Actual future net cash flows will also be affected by factors such as actual production levels and timing, and changes in governmental regulation or taxation, and may differ materially from estimated cash flows.

(1) **"Proved"** oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and natural gas liquids that geological and engineering data demonstrate with reasonable certainty can be recoverable in future years from known reservoirs under existing economic and operating conditions. Reservoirs are considered proved if economic producability is supported by either actual production or a conclusive formation test. "**Probable**" reserves are those additional reserves that are less likely to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of estimated proved plus probable reserves.

Depletion —As indicated previously our estimate of proved reserves are critical to calculating our unit-of-production depletion rates.

Another critical factor affecting our depletion rate is our determination that an impairment of unproved oil and gas properties has occurred. Costs incurred on an unproved oil and gas property are excluded from the depletion rate calculation until it is determined whether proved reserves are attributable to an unproved oil and gas property or upon determination that an unproved oil and gas property has been impaired. An unproved oil and gas property would likely be impaired if, for example, a dry hole has been drilled and there are no firm plans to continue drilling on the property. Also, the likelihood of partial or total impairment of a property increases as the expiration of the lease term approaches and there are no plans to drill on the property or to extend the term of the lease. We assess each of our unproved oil and gas properties for impairment on a quarterly basis. If we determined that an unproved oil and gas property has been totally or partially impaired we respectively include all or a portion of the accumulated costs incurred for that unproved oil and gas property in the calculation of our unit-of–production depletion rate. As at December 31, 2004, we had $20.4 million and $10.6 million of costs incurred on unproved oil and gas properties in the U.S. and China, respectively.

Our depletion rate is also affected by our estimates of future costs to develop the proved reserves. We estimate future development costs using quoted prices, historical costs and trends. It is difficult to predict prices for materials and services required to develop a field particularly over a period of years with rising oil and gas prices during which there is generally increased competition for a limited number of suppliers. We update our estimates of future costs to develop our proved reserves on a quarterly basis.

Impairment of Proved Oil and Gas Properties — We evaluate each of our cost center's proved oil and gas properties for impairment on a quarterly basis. The basis for calculating the amount of impairment is different for U.S. and Canadian GAAP purposes.

Effective January 2004, Accounting Guideline 16 "Oil and Gas Accounting - Full Cost" ("**AcG 16**") requires recognition and measurement processes to assess impairment of oil and gas properties ("**ceiling test**"). In the recognition of an impairment, the carrying value (1) of a cost center is compared to the undiscounted future net cash flows of that cost center's proved reserves using estimates of future oil and gas prices and costs plus the cost of unproved properties that have been excluded from the depletion calculation. If the carrying value is greater than the value of the undiscounted future net cash flows of the proved reserves plus the cost of unproved properties excluded from the depletion calculation, then the amount of the cost center's potential impairment must be measured. A cost center's impairment loss is measured by the amount its carrying value exceeds the discounted future net cash flows of its proved and probable reserves using estimates of future oil and gas prices and costs plus the cost of unproved properties that have been excluded from the depletion calculation and which contain no probable reserves. The net cash flows of a cost center's proved and probable reserves are discounted using a risk-free interest rate. The amount of the impairment loss is recognized as a charge to the results of operations and a reduction in the net carrying amount of a cost center's oil and gas properties. We provided for $16.3 million and $20.0 million in ceiling test impairments for our U.S. cost center for the years ended December 31, 2004 and 2003, respectively. No ceiling test impairments were provided for in the year ended December 31, 2002.

For U.S. GAAP, we follow the requirements of the SEC's Regulation S-X Article 4-10(c)4 for determining the limitation of capitalized costs. Accordingly, the carrying value (1) of a cost center's oil and gas properties cannot exceed the discounted future net cash flows of its proved reserves using period-end oil and gas prices and costs plus (i) the cost of properties that have been excluded

from the depletion calculation and (ii) the lower of cost or estimated fair value of unproved properties included in the depletion calculation less income tax effects related to differences between the book and tax basis of the properties. The net cash flows of a cost center's proved reserves are discounted using ten percent. The amount of the impairment loss is recognized as a charge to the results of operations and a reduction in the net carrying amount of a cost center's oil and gas properties. We provided for $15.0 million and $20.0 million in ceiling test impairments for our U.S. cost center for the years ended December 31, 2004 and 2003, respectively. No ceiling test impairments were provided for in the year ended December 31, 2002.

(1) For Canadian GAAP, the carrying value includes all capitalized costs for each cost center, including costs associated with asset retirement net of estimated salvage values, unproved properties and major development projects, less accumulated depletion and ceiling test impairments. This is essentially the same definition according to Regulation S-X, except that carrying value of assets should be net of deferred income taxes and costs of major development projects are to be considered separately for purposes of the ceiling test calculation.

Write-down of Non-Oil and Gas Properties — We incur various costs in the pursuit of GTL and EOR projects throughout the world. For Canadian GAAP, such costs incurred prior to signing an MOU, or similar agreements, are considered to be business development or project identification and are expensed as incurred. Upon executing an memorandum of understanding to determine the technical and commercial feasibility of a project, including studies for the marketability of the projects' products, we assume the feasibility and related costs incurred have potential future value, are probable of leading to a definitive agreement for the exploitation of proved reserves and should be capitalized. If no definitive agreement is reached, then the capitalized costs, which are deemed to have no future value, are written down to our results of operations with a corresponding reduction in our investments in GTL and EOR assets. For the years ended December 31, 2004, 2003 and 2002, we wrote down $0.3 million, $3.3 million and $2.4 million, respectively, of capitalized negotiation and feasibility costs associated with our GTL projects which did not result in definitive agreements.

For U.S. GAAP, feasibility, marketing and related costs incurred prior to executing a GTL or EOR definitive agreement are considered to be research and development and are expensed as incurred. For the years ended December 31, 2004, 2003 and 2002, we expensed $2.1 million, $0.8 million and $1.9 million, respectively, of feasibility, marketing and related costs incurred prior to executing definitive agreements.

Impact of New and Pending Canadian GAAP Accounting Standards

In December 2002, the Canadian Institute of Chartered Accountants ("**CICA**") approved Section 3110, "Asset Retirement Obligations" ("**S.3110**"). S.3110 requires liability recognition for retirement obligations associated with property, plant and equipment. These obligations are initially measured at fair value, which is the discounted future value of the liabilities. This fair value is capitalized as part of the cost of the related assets and amortized to expense over their useful life. The liabilities accrete until expected settlement of the retirement obligations. S.3110 is effective for fiscal years beginning on or after January 1, 2004. We elected early implementation of this accounting policy. Accordingly, effective January 1, 2003, we changed our accounting policy to capitalize asset retirement costs as part of the carrying value of our oil and gas properties and adjusted the amount of our site restoration liability to the present value of the liability for the corresponding asset retirement obligation as of this date. We have adopted the policy without retroactive adjustment of prior years because implementation of this change had an immaterial effect on our financial position and results of operations in prior years and in the current period.

In September 2003, the CICA issued AcG 16. AcG 16 is to be applied no later than January 1, 2004 and provides a new methodology for determining impairment of oil and gas properties, provides linkage to the new standards for determination of reserves and related disclosures under National Instrument 51-101 and revises certain other aspects of accounting for oil and gas operations under the full cost method.

Prior to January 2004, we applied hedge accounting to all derivative instruments used to manage price fluctuations in oil and natural gas prices. Effective January 1, 2004, we adopted CICA Accounting Guideline 13 ("**AcG 13**"), "Hedging Relationships". This guideline sets out the criteria that must be met in order to apply hedge accounting for derivatives. The guideline provides detailed guidance on the identification, designation, documentation and effectiveness of hedging relationships for purposes of applying hedge accounting, and the discontinuance of hedge accounting. Gains and losses on derivative instruments designated and qualifying as hedges under this guideline are recognized in earnings in the same period as the related hedged item. Ineffective hedging relationships and hedges not designated in a hedging relationship are carried at fair value in the statement of financial position, and subsequent changes in their fair value are recorded in the results of operations. The adoption of this accounting guideline did not have a material impact on the consolidated financial statements.

In July 2002, the CICA approved Section 3870, "Stock Based Compensation and Other Stock Based Payments" ("**S.3870**"). S.3870 applies to all stock based awards entered into during fiscal years beginning on or after January 1, 2002. For awards entered into with non-employees on or after January 1, 2002, S.3870 requires compensation costs to be recognized in the financial statements over the periods in which the stock options vest using the fair value based method of accounting. Although earlier implementation was encouraged, S.3870 did not require compensation costs to be recognized in the financial statements for stock based awards to employees and directors entered into during fiscal years beginning on or after January 1, 2002 until January 1, 2004. If earlier

implementation was not elected, S.3870 requires a retroactive application of the change in accounting for such stock based awards entered into between January 1, 2002 and December 31, 2003 with an option to restate the financial statements of prior periods. We implemented S.3870, as it relates to stock based awards to employees and directors, effective January 1, 2004 with a restatement of the financial statements of prior periods.

In January 2005, the CICA approved Section 1530 "Comprehensive Income" ("**S.1530**"), Section 3855 "Financial Instruments – Recognition and Measurement" ("**S.3855**") and Section 3865 "Hedges" ("**S.3865**") to harmonize financial instrument and hedge accounting with U.S. GAAP and introduce the concept of comprehensive income. S.1530 requires presentation of certain gains and losses outside of net income, such as unrealized gains and losses related to hedges or other derivative instruments. S.3855 establishes standards for recognizing and measuring financial assets and financial liabilities and non-financial derivatives as required to be disclosed under Section 3861 "Financial Instruments Disclosure and Presentation". S.3865 establishes standards for how and when hedge accounting may be applied. We apply SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities" for U.S. GAAP purposes and will implement S.3865 for Canadian GAAP for hedging activities. These sections apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006 and are not expected to have a material impact on our financial statements.

In January 2005, the CICA approved Section 3251 "Equity" which establishes standards for the presentation of equity and changes in equity during a reporting period. This section applies to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006 and is not expected to have a material impact on our financial statements.

The following standards issued by the CICA do not impact us at this time:

- Section 3861, "Financial Instruments Disclosure and Presentation", effective for fiscal years beginning on or after November 1, 2004.
- Accounting Guideline 15, "Consolidation of Variable Interest Entities", effective for annual and interim periods beginning on or after January 1, 2004.

Impact of New and Pending U.S. GAAP Accounting Standards

In June 2004, the Financial Accounting Standards Board ("**FASB**") issued an exposure draft of a proposed statement, "Fair Value Measurements" to provide guidance on how to measure the fair value of financial and non-financial assets and liabilities when required by other authoritative accounting pronouncements. The proposed statement attempts to address concerns about the ability to develop reliable estimates of fair value and inconsistencies in fair value guidance provided by current U.S. GAAP, by creating a framework that clarifies the fair value objective and its application in U.S. GAAP. In addition, the proposal expands disclosures required about the use of fair value to re-measure assets and liabilities. The standard would be effective for financial statements issued for fiscal years beginning after June 15, 2005.

In September of 2004, the SEC released Staff Accounting Bulletin No. 106, which provides guidance regarding the interaction of Statement of Financial Accounting Standard No. 143, Accounting for Asset Retirement Obligations ("**SFAS 143**") with the full cost accounting rules in Article 4-10 of Regulation S-X. This bulletin clarifies the treatment of assets and liabilities resulting from the implementation of SFAS 143 on the full cost ceiling test and the calculation of depletion, depreciation and amortization. We are in compliance with the provisions of Staff Accounting Bulletin No. 106.

In December 2004, the FASB issued a revision to SFAS No. 123, "Accounting for Stock Based Compensation", which supersedes APB No. 25, "Accounting for Stock Issued to Employees". This Statement requires measurement of the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the date of the grant and recognition of the cost in the results of operations over the period during which an employee is required to provide service in exchange for the award. No compensation cost is recognized for equity instruments for which employees do not render the requisite service. We apply APB Opinion No. 25, as interpreted by FASB Interpretation No. 44, in accounting for awards issued from our stock option plan and do not recognize compensation costs in our financial statements for stock options issued to our employees and directors. This statement is effective for the first interim or annual reporting period that begins after June 15, 2005 and may be implemented on a modified prospective or retrospective basis. We have elected to implement this statement on a modified prospective basis starting in the third quarter of 2005. Under the modified prospective basis we would recognize stock based compensation in our U.S. GAAP results of operations for the unvested portion of awards outstanding as of July 1, 2005 and for all awards granted after July 1, 2005.

The following standards issued by the FASB do not impact us at this time:

SFAS No. 151, "Inventory Costs—an amendment of ARB No. 43, Chapter 4" effective for inventory costs incurred during fiscal years beginning after June 15, 2005.

SFAS No. 153, "Exchanges of Nonmonetary Assets—an amendment of APB Opinion No. 29" effective for nonmonetary asset exchanges occurring in fiscal years beginning after June 15, 2005.

Off Balance Sheet Arrangements

At December 31, 2004 and 2003, we did not have any relationships with unconsolidated entities or financial partnerships, such as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. In addition, we do not engage in trading activities involving non-exchange traded contracts. As such, we are not materially exposed to any financing, liquidity, market or credit risk that could arise if we had engaged in such relationships. We do not have relationships and transactions with persons or entities that derive benefits from their non-independent relationship with us, or our related parties, except as disclosed herein.

Related Party Transactions

We have entered into agreements with a number of entities, some of which are related through common directors or shareholders, to share administrative personnel, aircraft, office space and facilities on a cost recovery basis. The agreement for the usage of aircraft was terminated in 2003. The costs incurred in the normal course of business with respect to the above arrangements amounted to $0.9 million each for 2004 and 2003 and $1.2 million for 2002. In addition, a company controlled by a director provides us with consulting services. Consulting services and out of pocket expenses paid to this company were $0.7 million for 2004 and $0.4 million each for 2003 and 2002. At year-end, amounts included in accounts payable under these arrangements totaled $0.1 million in 2004 and 2003 and $0.8 million in 2002.

In 2003, we borrowed $1.25 million from a related company controlled by one of our directors. The loan, plus accrued interest, was repaid in September 2003.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Equity Market Risks

We currently have limited production in the U.S and China, which have not generated sufficient cash from operations to fund our exploration and development activities. Historically, we have relied on the equity markets as the primary source of capital to fund our expansion and growth opportunities. We estimate that we will need approximately $40 million from the equity markets to fund our capital investment programs for 2005.

We can give no assurance that we will be successful in obtaining financing from equity markets as and when needed. Factors beyond our control may make it difficult or impossible for us to obtain equity financing on favorable terms or at all. Failure to obtain any required equity financing on a timely basis may cause us to postpone our development plans, forfeit rights in some or all of our projects or reduce or terminate some or all of our operations.

Commodity Price Risk

Commodity price risk related to crude oil prices is one of our most significant market risk exposures. Crude oil prices and quality differentials are influenced by worldwide factors such as OPEC actions, political events and supply and demand fundamentals. To a lesser extent we are also exposed to natural gas price movements. Natural gas prices are generally influenced by oil prices, North American supply and demand and local market conditions. We estimate that our net income and cash from operations for 2005 would change $1.0 million and $0.9 million for every $1.00/Bbl change in WTI prices and $0.50/Mcf in natural gas prices, respectively.

We periodically engage in the use of derivatives to hedge our cash flow from operations but have no hedge contracts in place as at December 31, 2004. See Note 12 to the Consolidated Financial Statements in Item 8.

Decreases in oil and natural gas prices would negatively impact our results of operations as a direct result of a reduction in revenues but may also do so in the ceiling test calculation for the impairment of our oil and gas properties. On a quarterly basis, we compare the value of our proved and probable reserves, using estimated future oil and gas prices [(1)], to the carrying value of our oil and gas properties. The ceiling test calculation is sensitive to oil and gas prices and in a period of declining prices could result in a charge to our results of operations as we experienced in 2001 when we recorded a $14.0 million provision for impairment for Canadian GAAP and an additional $10.0 million for U.S. GAAP mainly due to a decline in oil and gas prices. Decreases in oil and gas prices from those used in our ceiling test calculation as at December 31, 2004 as discussed above in "Critical Accounting Principles and Estimates - Impairment of Proved Oil and Gas Properties" may result in additional impairment provisions on our U.S. oil and gas properties.

(1) The recoverable value of probable reserves is included only for the measurement of the impairment of the carrying value of oil and gas properties as required under Canadian GAAP but not for U.S. GAAP. Additionally, U.S. GAAP requires the use of period end oil and gas prices to measure the amount of the impairment rather than estimated future oil and gas prices as required by Canadian GAAP. See 'Critical Accounting Principles and Estimates' in Item 7 in this Annual Report on Form 10-K for the difference between Canadian and U.S. GAAP in calculating the impairment provision for oil and gas properties.

Foreign Currency Rate Risk

In the international petroleum industry, most production is bought and sold in U.S. dollars or with reference to the U.S. dollar. Accordingly, we do not expect to face foreign exchange risks associated with our production revenues.

Most of our business transactions, in the countries in which we operate, are conducted in U.S. dollars or currencies, such as Chinese renminbi, which are pegged to the U.S. dollar. As a result, we incurred insignificant foreign currency exchange gains or losses during the three years ended December 31, 2004.

Interest Rate Risk

We currently have minimal debt obligations and, therefore, we do not believe that we face any undue financial risk from interest rate fluctuations.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Financial Statements and Related Information

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Shareholders of
Ivanhoe Energy Inc.:

We have audited the consolidated balance sheets of Ivanhoe Energy Inc. as at December 31, 2004 and 2003 and the consolidated statements of loss and shareholders' equity and cash flow for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). These standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Ivanhoe Energy Inc. as at December 31, 2004 and 2003 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004 in accordance with Canadian generally accepted accounting principles.

(signed) Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Alberta, Canada

February 11, 2005

COMMENTS BY AUDITORS FOR U.S. READERS ON CANADA — U.S. REPORTING DIFFERENCES

The standards of the Public Company Accounting Oversight Board (United States) require the addition of an explanatory paragraph (following the opinion paragraph) when there are changes in accounting principles that have a material effect on the comparability of the Company's financial statements and changes in accounting principles that have been implemented in the financial statements. As discussed in Note 2 to the consolidated financial statements, the Company changed its method of accounting for asset retirement obligations (Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3110), stock-based compensation (CICA Handbook Section 3870), and the full cost method of accounting (CICA Accounting Guideline 16). Our report to the shareholders dated February 11, 2005 is expressed in accordance with Canadian reporting standards, which do not require a reference to such changes in accounting principles in the auditors' report when the changes are properly accounted for and adequately disclosed in the financial statements.

(signed) Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Alberta, Canada

February 11, 2005

IVANHOE ENERGY INC.
Consolidated Balance Sheets
(stated in thousands of U.S. Dollars, except share amounts)

	As at December 31,	
	2004	**2003**
		(restated Notes 2 and 9)
Assets		
Current Assets		
Cash and cash equivalents	$ 9,322	$ 14,491
Accounts receivable *(Note 3)*	5,377	2,720
Prepaid and other current assets	812	409
	15,511	17,620
Long term assets *(Note 5)*	6,424	998
Oil and gas properties and investments, net *(Note 4)*	96,551	87,956
	$ 118,486	$ 106,574
Liabilities and Shareholders' Equity		
Current Liabilities		
Accounts payable and accrued liabilities	$ 9,845	$ 4,516
Note payable - current portion *(Note 6)*	1,667	167
	11,512	4,683
Long term debt *(Note 6)*	2,639	833
Asset retirement obligations *(Note 7)*	749	521
Commitments and contingencies *(Note 17)*		
Shareholders' Equity		
Share capital, issued and outstanding 169,664,911 common shares; December 31, 2003 161,359,339 common shares *(Note 8)*	183,617	161,075
Contributed surplus	1,748	516
Accumulated deficit	(81,779)	(61,054)
	103,586	100,537
	$ 118,486	$ 106,574

(See accompanying Notes to Consolidated Financial Statements)

Approved by the Board:

(signed) David R. Martin
Director

(signed) E. Leon Daniel
Director

IVANHOE ENERGY INC.
Consolidated Statements of Loss
(stated in thousands of U.S. Dollars, except share amounts)

	Year ended December 31,		
	2004	2003	2002
		(restated Notes 2 and 9)	
Revenue			
Oil and gas revenue	$ 17,795	$ 9,569	$ 8,329
Interest income	202	90	108
	17,997	9,659	8,437
Expenses			
Operating costs	5,073	4,293	3,841
General and administrative	9,188	8,211	5,955
Depletion and depreciation	7,482	3,829	3,312
Interest expense	379	184	23
Write-downs and provision for impairment *(Notes 4 and 13)*	16,600	23,321	2,436
	38,722	39,838	15,567
Net Loss	$ 20,725	$ 30,179	$ 7,130
Net Loss per share - Basic and Diluted ***(Note 15)***	$ 0.12	$ 0.20	$ 0.05
Weighted Average Number of Shares (in thousands) ***(Note 15)***	167,612	150,154	142,314

(See accompanying Notes to Consolidated Financial Statements)

IVANHOE ENERGY INC.
Consolidated Statements of Shareholders' Equity
(stated in thousands of U.S. Dollars, except share amounts)

	Share Capital		Contributed	Accumulated	
	Shares	Amount	Surplus	Deficit	Total
Balance December 31, 2001	139,267	$ 120,392	$ -	$ (23,495)	$ 96,897
Net loss, as previously reported	-	-	-	(6,819)	(6,819)
Retroactive application of change in accounting policy for stock based compensation (Notes 2 and 9)	-	-	311	(311)	-
Net loss, as restated				(7,130)	
Shares issued on private placements, net of share issue costs	5,000	9,964	-	-	9,964
Shares issued on exercise of options	163	119	-	-	119
Shares issued for services	201	387	-	-	387
Elimination of employee loans *(Note 8)*	-	409	-	-	409
Retirement of shares	(165)	(159)	-	(250)	(409)
Balance December 31, 2002 (as restated)	144,466	131,112	311	(30,875)	100,548
Net loss, as previously reported	-	-	-	(29,703)	(29,703)
Retroactive application of change in accounting policy for stock based compensation (Notes 2 and 9)	-	-	476	(476)	-
Net loss, as restated				(30,179)	
Shares issued on private placements, net of share issue costs	12,654	24,070	-	-	24,070
Shares issued on conversion of debenture (Note 8)	2,000	1,000	-	-	1,000
Shares issued on exercise of warrants	250	425	-	-	425
Shares issued on exercise of options (as restated)	1,363	3,773	(271)	-	3,502
Shares issued for services	626	695	-	-	695
Balance December 31, 2003, (as restated)	161,359	161,075	516	(61,054)	100,537
Net loss	-	-	-	(20,725)	(20,725)
Shares issued on private placements, net of share issue costs	7,173	20,428	-	-	20,428
Shares issued on exercise of options	975	1,767	(44)	-	1,723
Shares issued for services	158	347	-	-	347
Stock based compensation	-	-	1,276	-	1,276
Balance December 31, 2004	169,665	$ 183,617	$ 1,748	$ (81,779)	$ 103,586

(See accompanying Notes to Consolidated Financial Statements)

IVANHOE ENERGY INC.
Consolidated Statements of Cash Flow
(stated in thousands of U.S. Dollars)

	Year ended December 31,		
	2004	2003	2002
		(restated Notes 2 and 9)	
Operating Activities			
Net loss	$ (20,725)	$ (30,179)	$ (7,130)
Items not requiring use of cash:			
Depletion and depreciation	7,482	3,829	3,312
Write-downs and provision for impairment *(Notes 4 and 13)*	16,600	23,321	2,436
Stock based compensation *(Note 2 and 9)*	1,276	476	311
Other	47	-	-
Changes in non-cash working capital items	(648)	1,031	(1,049)
	4,032	(1,522)	(2,120)
Investing Activities			
Capital investments	(46,454)	(15,391)	(18,828)
Proceeds from sale of assets *(Note 4)*	13,958	-	5,351
Equity investment and other related costs *(Note 5)*	(5,016)	(500)	-
Other	(410)	(37)	(65)
Changes in non-cash working capital items	3,264	(537)	(638)
	(34,658)	(16,465)	(14,180)
Financing Activities			
Shares issued on private placements, net of share issue costs	20,428	24,070	9,964
Shares issued on exercise of options and warrants	1,723	3,928	119
Proceeds from notes and advances *(Note 6)*	14,000	1,750	500
Payments of note payable *(Note 6)*	(694)	(1,250)	-
Redemption of advance payable *(Note 6)*	(10,000)	-	-
	25,457	28,498	10,583
Increase (decrease) in cash and cash equivalents, for the year	(5,169)	10,511	(5,717)
Cash and cash equivalents, beginning of year	14,491	3,980	9,697
Cash and cash equivalents, end of year	$ 9,322	$ 14,491	$ 3,980
Supplementary Information Regarding Non-Cash Transactions			
Financing activities, non-cash			
Shares issued on conversion of debenture *(Note 8)*	$ -	$ 1,000	$ -
Included in the above are the following:			
Taxes paid (refunded)	$ 3	$ 6	$ (27)
Interest paid	$ 317	$ 96	$ 74
Changes in non-cash working capital items			
Operating Activities:			
Accounts receivable	$ (1,949)	$ (201)	$ 38
Other current assets	(403)	282	(316)
Accounts payable and accrued liabilities	1,704	950	(771)
	(648)	1,031	(1,049)
Investing Activities			
Accounts receivable	(708)	-	(619)
Accounts payable and accrued liabilities	3,972	(537)	(19)
	3,264	(537)	(638)
	$ 2,616	$ 494	$ (1,687)

(See accompanying Notes to Consolidated Financial Statements)

Notes to the Consolidated Financial Statements
(all tabular amounts are expressed in thousands of U.S. Dollars, except share amounts)

1. NATURE OF OPERATIONS

Ivanhoe Energy Inc., a Canadian company, and its subsidiaries are focused internationally on three major strategies: 1) conventional exploration and production of oil and gas 2) enhanced oil recovery ("**EOR**") development projects including the application of heavy-to-light oil ("**HTL**") upgrading technology and 3) the monetization of stranded gas reserves through a licensed gas-to-liquids ("**GTL**") technology. Conventional oil and gas operations are currently carried out in the U.S. and China and GTL, EOR and HTL projects for a number of countries are in various stages.

2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements have been prepared in accordance with generally accepted accounting principles ("**GAAP**") in Canada. The impact of material differences between Canadian and U.S. GAAP on the consolidated financial statements is disclosed in Note 19.

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts and other disclosures in these consolidated financial statements. Actual results may differ from those estimates.

Certain items in the 2003 and 2002 financial statements have been reclassified for comparison to the 2004 presentation.

Changes in Accounting Policies

Asset Retirement Costs

Prior to January 2003, the Company had estimated its future site restoration and abandonment costs associated with its oil and gas properties and amortized this estimate to operations using the unit-of-production method based upon estimated proved reserves. The provision was included with depletion and depreciation expense.

The Canadian Institute of Chartered Accountants ("**CICA**") approved Section 3110, "Asset Retirement Obligations" which requires, for fiscal years beginning after January 1, 2004, asset retirement costs and liabilities associated with site restoration and abandonment of tangible long-lived assets be initially measured at a fair value which approximates the cost a third party would incur in performing the tasks necessary to retire such assets. The fair value is recognized in the financial statements at the present value of expected future cash outflows to satisfy the obligation. Subsequent to the initial measurement, the effect of the passage of time on the liability for the asset retirement obligation (accretion expense) and the amortization of the asset retirement cost are recognized in the results of operations.

The Company elected early implementation of this accounting policy. Accordingly, effective January 1, 2003, the Company changed its accounting policy to capitalize asset retirement costs as part of the carrying value of its oil and gas properties and adjusted the amount of its site restoration liability to the present value of the liability for the corresponding asset retirement obligation as of this date. The Company has adopted the policy without retroactive adjustment of prior years because implementation of this change had an immaterial effect on the Company's financial position and results of operations in prior years (See Notes 4 and 7).

Stock Based Compensation

Prior to January 1, 2004, the Company accounted for share options granted to employees and directors using the intrinsic-value of the stock options. Under this method, compensation costs were not recognized in the financial statements for stock options granted at market value but rather disclosure was required, on a pro forma basis, of the impact on net income of using the fair value at the stock option grant date. The Company recognizes compensation costs in its financial statements for stock options granted to non-employees after January 1, 2002 based on the fair value of the stock options at the date granted.

The CICA approved Section 3870, "Stock Based Compensation and Other Stock Based Payments" which requires, for fiscal years beginning on or after January 1, 2004, compensation costs to be recognized in the financial statements using the fair value based method of accounting for all stock options granted after January 1, 2002. Implementation of this change in accounting policy requires retroactive application with the option of restating financial statements of prior periods.

Accordingly, effective January 1, 2004, the Company changed its accounting policy, for Canadian GAAP purposes, to recognize compensation costs using the fair value based method of accounting for stock options granted to employees and directors after January 1, 2002. This change has been adopted retroactively and the Company has elected to restate the financial statements of prior periods (See Note 9). The Company uses the Black-Scholes option-pricing model for determining the fair value of all stock options issued at grant date.

Principles of Consolidation

These consolidated financial statements include the accounts of Ivanhoe Energy Inc. and its subsidiaries, all of which are wholly owned. The Company conducts most exploration, development and production activities in its oil and gas business jointly with others and our accounts reflect only the Company's proportionate interest.

All inter-company transactions and balances have been eliminated for the purposes of these consolidated financial statements.

Foreign Currency Translation

The Company uses the U.S. Dollar as its functional currency since it is the currency in which the worldwide petroleum business denominates its business. Monetary assets and liabilities denominated in foreign currencies are converted to the U.S. Dollar at the exchange rate in effect at the balance sheet date and non-monetary assets and liabilities at the exchange rates in effect at the time of acquisition or issue. Revenues and expenses are converted to the U.S. Dollar at rates approximating exchange rates in effect at the time of the transactions. Exchange gains or losses resulting from the period-end translation of monetary assets and liabilities denominated in foreign currencies are reflected in the results of operations.

Cash and Cash Equivalents

Cash and cash equivalents include short-term money market instruments with terms to maturity, at the date of issue, not exceeding 90 days.

Financial Instruments

The fair value of the Company's cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, note payable and long term debt approximates the carrying values due to the immediate or short-term maturity of these financial instruments.

Oil and Gas Properties

Full Cost Accounting

The Company follows the full cost method of accounting for oil and gas operations whereby all exploration and development expenditures are capitalized on a country-by-country (cost center) basis. Such expenditures include lease and royalty interest acquisition costs, geological and geophysical expenses, carrying charges for unproved properties, costs of drilling both successful and unsuccessful wells, gathering and production facilities and equipment, financing, administrative costs related to capital projects and asset retirement costs. The Company periodically evaluates its unproved properties for exploration and exploitation opportunities. If the Company determines that the exploration or exploitation potential of an unproved property has diminished, all, or a portion, of the costs incurred on such property is impaired and transferred to the carrying value of proved oil and gas properties. Proceeds from sales of oil and gas properties are recorded as reductions in the carrying value of proved oil and gas properties, unless such amounts would significantly alter the rate of depreciation and depletion, whereupon gains or losses would be recognized in income. Maintenance and repair costs are expensed as incurred, while improvements and major renovations are capitalized.

Depletion

The Company’s share of costs for proved oil and gas properties accumulated within each cost center, including a provision for future development costs, are depleted using the unit-of-production method over the life of the Company’s share of estimated remaining proved oil and gas reserves. Significant development projects and expenditures on unproved properties are excluded from the depletion calculation until evaluated. Natural gas reserves and production are converted to a barrels of oil equivalent using a generally recognized industry standard in which six thousand cubic feet of gas is equal to one barrel of oil. Barrels of oil equivalent may be misleading, particularly if used in isolation. The conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Impairment of Proved Oil and Gas Properties

Prior to January 2004, impairment of oil and gas properties was based on the amount by which a cost center's carrying value exceeded its undiscounted future net cash flows from proved reserves using period-end, non-escalated prices and costs, less an estimate for future general and administrative expenses, financing costs and income taxes ("**ceiling test**").

Effective January 2004, Accounting Guideline 16 "Oil and Gas Accounting - Full Cost" requires recognition and measurement processes to assess impairment of oil and gas properties. In the recognition of an impairment, the carrying value of a cost center is compared to the undiscounted future net cash flows of that cost center's proved reserves using estimates of future oil and gas prices and costs plus the cost of unproved properties that have been excluded from the depletion calculation. If the carrying value is greater than the value of the undiscounted future net cash flows of the proved reserves plus the cost of unproved properties excluded from the depletion calculation, then the amount of the cost center's potential impairment must be measured. A cost center's impairment loss is measured by the amount its carrying value exceeds the discounted future net cash flows of its proved and probable reserves using estimates of future oil and gas prices and costs plus the cost of unproved properties that have been excluded from the depletion calculation and which contain no probable reserves. The net cash flows of a cost center's proved and probable reserves are discounted using a risk-free interest rate. The amount of the impairment loss is recognized as a charge to the results of operations and a reduction in the net carrying amount of a cost center's oil and gas properties.

Asset Retirement Costs

The Company measures the expected costs required to retire its producing U.S. oil and gas properties at a fair value which approximates the cost a third party would incur in performing the tasks necessary to abandon the field and restore the site. The fair value is recognized in the financial statements at the present value of expected future cash outflows to satisfy the obligation. The Company does not make such a provision for its oil and gas operations in China as the remaining life of its Dagang production sharing contract is less than the remaining economic life of the field and there is no obligation on the Company's part to contribute to the future cost to abandon the field and restore the site.

Asset retirement costs are being depleted using the unit of production method based on estimated proved reserves and are included with depletion and depreciation expense. The accretion of the liability for the asset retirement obligation is included with interest expense.

Investments in GTL and EOR Projects

The Company incurs various costs in the pursuit of GTL and EOR projects throughout the world. Such costs incurred prior to signing a memorandum of understanding ("**MOU**"), or similar agreements, are considered to be business development or project identification and are expensed as incurred. Upon executing an MOU to determine the technical and commercial feasibility of a project, including studies for the marketability for the projects products, the Company assumes the feasibility and related costs incurred have potential future value, are probable of leading to a definitive agreement for the exploitation of proved reserves and should be capitalized. If no definitive agreement is reached, then the project's capitalized costs, which are deemed to have no future value, are written down to the results of operations with a corresponding reduction in the investments in GTL and EOR assets.

Furniture and Fixtures

Furniture and fixtures are stated at cost. Depreciation is provided on a straight-line basis over the estimated useful life of the respective assets, at rates ranging from three to ten years.

Oil and Gas Revenue

Sales of crude oil and natural gas are recognized in the period in which the product is delivered to the customer. Oil and gas revenue represents the Company's share and is recorded net of royalty payments to governments and other mineral interest owners.

In China, the Company conducts operations jointly with the government of China in accordance with a production-sharing contract. Under this contract, the Company pays both its share and the government's share of operating and capital costs. The Company recovers the government's share of these costs from future revenues or production over the life of the production-sharing contract. The government's share of operating costs is recorded in operating expense when incurred and capital costs are recorded in oil and gas properties and expensed to depletion and depreciation in the year recovered. All recoveries of the government's share of costs are recorded as oil and gas revenue in the year of recovery.

Earnings or Loss Per Share

Basic earnings or loss per share is calculated by dividing the net earnings or loss to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share reflects the potential dilution that would occur if stock options and warrants were exercised. The treasury stock method is used in calculating diluted earnings per share, which assumes that any proceeds received from the exercise of in-the-money stock options and warrants would be used to purchase common shares at the average market price for the period (See Note 15). The Company does not report diluted loss per share amounts, as the effect would be antidilutive to the common shareholders.

Income Taxes

The Company follows the liability method of accounting for future income taxes. Under the liability method, future income taxes are recognized to reflect the expected future tax consequences arising from tax loss carry-forwards and temporary differences between the carrying value and the tax basis of the Company's assets and liabilities.

Stock Based Compensation

The Company has an Employees' and Directors' Equity Incentive Plan consisting of stock option, bonus and an employee share purchase plan (See Note 9). The Company accounts for equity-based compensation under this plan using the fair value based method of accounting for all stock options granted after January 1, 2002. Compensation costs are recognized in the results of operations over the periods in which the stock options vest for all stock options granted based on the fair value of the stock options at the date granted. The Company uses the Black-Scholes option-pricing model for determining the fair value of stock options issued at grant date. As of the date stock options are granted, the Company estimates a percentage of stock options issued to employees and directors it expects to be forfeited. Compensation costs are not recognized for stock option awards forfeited due to a failure to satisfy the service requirement for vesting. Compensation costs are adjusted for the actual amount of forfeitures in the period in which the stock options expire.

Upon the exercise of stock options, share capital is credited for the fair value of the stock options at the date granted with a charge to contributed surplus. Consideration paid upon the exercise of the stock options is also credited to share capital.

Compensation expenses are recognized when shares are issued from the stock bonus plan. The employee share purchase portion of the plan has not yet been activated.

Derivative Activities

Prior to January 2004, the Company applied hedge accounting to all derivative instruments used to manage price fluctuations in oil and natural gas prices.

Effective January 1, 2004, the Company adopted CICA Accounting Guideline 13 ("AcG 13"), "Hedging Relationships". This guideline sets out the criteria that must be met in order to apply hedge accounting for derivatives. The guideline provides detailed guidance on the identification, designation, documentation and effectiveness of hedging relationships for purposes of applying hedge accounting, and the discontinuance of hedge accounting. Gains and losses on derivative instruments designated and qualifying as hedges under this guideline are recognized in earnings in the same period as the related hedged item. Ineffective hedging relationships and hedges not designated in a hedging relationship are carried at fair value in the statement of financial position, and subsequent changes in their fair value are recorded in the results of operations. The adoption of this accounting guideline did not have a material impact on the consolidated financial statements (See Note 12).

Impact of New and Pending Canadian GAAP Accounting Standards

In January 2005, the CICA approved Section 1530 "Comprehensive Income" ("**S.1530**"), Section 3855 "Financial Instruments – Recognition and Measurement" ("**S.3855**") and Section 3865 "Hedges" ("**S.3865**") to harmonize financial instrument and hedge accounting with U.S. GAAP and introduce the concept of comprehensive income. S.1530 requires presentation of certain gains and losses outside of net income, such as unrealized gains and losses related to hedges or other derivative instruments. S.3855 establishes standards for recognizing and measuring financial assets and financial liabilities and non-financial derivatives as required to be disclosed under Section 3861 "Financial Instruments Disclosure and Presentation". S.3865 establishes standards for how and when hedge accounting may be applied. The Company applies SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities" for U.S. GAAP purposes and will implement S.3865 for Canadian GAAP for hedging activities. These sections apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006 and are not expected to have a material impact on the Company's financial statements.

In January 2005, the CICA approved Section 3251 "Equity" which establishes standards for the presentation of equity and changes in equity during a reporting period. This section applies to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006 and is not expected to have a material impact on the Company's financial statements.

The following standards issued by the CICA do not impact the Company at this time:

- Section 3861, "Financial Instruments Disclosure and Presentation", effective for fiscal years beginning on or after November 1, 2004.
- Accounting Guideline 15, "Consolidation of Variable Interest Entities", effective for annual and interim periods beginning on or after November 1, 2004.

3. CONCENTRATION OF CREDIT RISKS

The Company sells oil and natural gas products to pipelines, refineries, major oil companies and foreign national petroleum companies. Where possible, credit is extended based on an evaluation of the customer's financial condition and historical payment record.

The following summarizes the accounts receivable balances and revenues from significant customers:

	Accounts Receivable as at December 31,		Oil and Gas Revenues for the Year Ended December 31,		
	2004	2003	2004	2003	2002
U.S. Customers					
A	$ 542	$ 407	$ 6,140	$ 4,392	$ 2,916
B	398	-	1,202	-	-
C	193	175	1,040	986	1,764
D	229	-	441	-	-
E	71	60	300	273	390
All others	20	15	188	65	29
	1,453	657	9,311	5,716	5,099
China Customer					
A	1,982	950	8,484	4,103	3,230
	3,435	1,607	17,795	9,819	8,329
Receivables from partners	1,652	947	-	-	-
Other receivables	290	166	-	-	-
	$ 5,377	$ 2,720	$ 17,795	$ 9,819	$ 8,329

Oil and gas revenues for the year ended December 31, 2003 in the table above do not include $0.3 million of oil hedge losses from derivative activities.

Accounts receivable as at December 31, 2004 and 2003 in the table above include $1.7 million and $0.9 million, respectively, of costs billed to joint venture partners and advances to partners for joint operations where the Company is not the operator.

4. OIL AND GAS PROPERTIES AND INVESTMENTS

Capital assets categorized by segment are as follows:

	As at December 31, 2004				
	Oil and Gas				
	U.S.	China	GTL	EOR	Total
Oil and Gas Properties:					
Proved	$ 81,648	$ 35,771	$ -	$ -	$ 117,419
Unproved	20,447	10,581	-	-	31,028
	102,095	46,352	-	-	148,447
Accumulated depletion	(10,956)	(6,663)	-	-	(17,619)
Accumulated provision for impairment	(50,350)	-	-	-	(50,350)
	40,789	39,689	-	-	80,478
GTL and EOR Investments:					
GTL master license	-	-	10,000	-	10,000
Feasibility studies and other deferred costs	-	-	3,793	2,091	5,884
	-	-	13,793	2,091	15,884
Furniture and equipment	417	84	-	11	512
Accumulated depreciation	(300)	(22)	-	(1)	(323)
	117	62	-	10	189
	$ 40,906	$ 39,751	$ 13,793	$ 2,101	$ 96,551

	As at December 31, 2003				
	Oil and Gas				
	U.S.	China	GTL	EOR	Total
Oil and Gas Properties:					
Proved	$ 57,545	$ 29,201	$ -	$ -	$ 86,746
Unproved	27,534	3,639	-	-	31,173
	85,079	32,840	-	-	117,919
Accumulated depletion	(6,442)	(3,804)	-	-	(10,246)
Accumulated provision for impairment	(34,000)	-	-	-	(34,000)
	44,637	29,036	-	-	73,673
GTL and EOR Investments:					
GTL master license	-	-	10,000	-	10,000
Feasibility studies and other deferred costs	-	-	4,072	-	4,072
	-	-	14,072	-	14,072
Furniture and equipment	433	31	-	-	464
Accumulated depreciation	(253)	-	-	-	(253)
	180	31	-	-	211
	$ 44,817	$ 29,067	$ 14,072	$ -	$ 87,956

Effective January 1, 2003, the Company capitalized $0.3 million as a result of implementation of a new accounting policy on asset retirement obligations. For the years ended December 31, 2004 and 2003, $0.2 million and $0.1 million, respectively, of future asset retirement costs were capitalized (See Note 2).

Costs as at December 31, 2004 and 2003 of $31.0 million and $31.2 million, respectively, related to unproved oil and gas properties were excluded from the depletable cost centers

For the years ended December 31, 2004 and 2003, general and administrative expenses related directly to oil and gas acquisition, exploration and development activities, and investments in GTL and EOR projects of $3.8 million and $1.8 million, respectively, were capitalized.

United States

The Company's U.S. oil and gas operations are primarily conducted through joint operations with other oil and gas companies in California, Texas and Wyoming. Costs capitalized in the U.S. cost center under the full cost method of accounting are as follows:

	As at December 31, 2004	As at December 31, 2003
California	$ 74,155	$ 59,386
Texas	24,239	24,046
Wyoming	2,054	-
Other	1,647	1,647
	$ 102,095	$ 85,079

Included in the carrying value for the Company's California properties are $9.2 million of costs incurred to acquire overriding royalties in various exploration prospects and producing properties.

During 2004, the Company sold its working interest in one of its California producing properties for $0.5 million. The sale proceeds were credited to the U.S. cost center as the sale did not significantly alter the depletion rate for the U.S. cost center.

The provision for impairment calculated for U.S. oil and gas properties was $16.3 million and $20.0 million for 2004 and 2003, respectively. No provision for impairment of U.S. oil and gas properties was required for 2002 (See Note 13).

China

The Company currently holds a production-sharing contract with China National Petroleum Corporation ("**CNPC**") to develop existing oil properties in the Dagang region. In January 2004, the Company signed farm-out and joint operating agreements with Richfirst Holdings Limited ("Richfirst"), a wholly-owned subsidiary of China International Trust and Development Corporation, to acquire a forty percent working interest in the Dagang field for an up-front payment of $20.0 million following receipt of Chinese regulatory approvals in June 2004. Richfirst will have the right to exchange its working interest in the Dagang field for common shares in the Company's wholly owned subsidiary, Sunwing Energy Ltd. ("**Sunwing**"), should the Company obtain a public listing for Sunwing, or for the Company's common shares. Richfirst's right to exchange its working interest for the Company's common shares expires in December 2005. The Company and Richfirst incur 100% of the costs to earn 82% of the production, before recovery of costs incurred, reverting to a 49% share post recovery. The carrying value of the Company's China oil and gas properties was reduced by $13.5 million for the amount of the proceeds associated with the farm-in of Richfirst to the Dagang field. The reduction in the carrying value did not significantly alter the depletion rate of the China cost center.

The Company held a production-sharing contract to develop existing oil fields in the Daqing region until the sale of its interest in the field in January 2002. The Company retains an overriding royalty on future production.

The Company also holds a production-sharing contract with CNPC in a contract area, known as the Zitong block located in the northwestern portion of the Sichuan Basin. Under the terms of the production-sharing contract, the Company will develop natural gas deposits within the block and in return will receive approximately 75% of the revenue until costs are recovered and approximately 45% thereafter. CNPC has the option, at the end of appraisal activities, to participate with the Company in any proposed field developments, with up to a 51% working interest.

Costs capitalized in the China cost center under the full cost method of accounting are as follows:

	As at December 31, 2004	As at December 31, 2003
Dagang Project	$ 32,061	$ 25,357
Sichuan Basin	10,581	3,639
Daqing Project	3,710	3,844
	$ 46,352	$ 32,840

Gas-to-Liquids

The Company owns a master license from Syntroleum Corporation ("**Syntroleum**") permitting the Company to use their proprietary GTL process in an unlimited number of projects around the world. The Syntroleum GTL process converts natural gas into synthetic liquid hydrocarbons that can be utilized to develop, among other things, clean-burning diesel fuel. In July 2003, the master license was amended in respect of GTL projects in which both the Company and Syntroleum participate such that no additional license fees or royalties will be payable by the Company and that Syntroleum will contribute, to any such project, the right to manufacture specialty and lubricant products. Both companies have the right to pursue GTL projects independently, but the Company would be required to pay the normal license fees and royalties in such projects.

Since 2000, the Company has undertaken detailed project feasibility studies for the construction, operation and cost of GTL plants in Qatar, Egypt, Oman and Bolivia. In addition, the Company has conducted marketing, commercialization and transportation feasibility studies. Marketing studies were conducted for both European and the Asia Pacific regions for GTL diesel and specialty fuels.

For the years ended December 31, 2004, 2003 and 2002, the Company wrote down \$0.3 million, \$3.3 million and \$2.4 million, respectively, of capitalized negotiation and feasibility costs associated with our GTL projects which did not result in definitive agreements. Other costs associated with feasibility studies and related costs, which are deemed to have future value, remain capitalized. Recovery of the GTL costs capitalized is dependent upon finalizing contracts to access natural gas reserves in the respective countries and the successful completion of GTL processing plants.

Enhanced Oil Recovery

In the fourth quarter of 2004, the Company signed memoranda of understanding with the Ministry of Oil of the Government of Iraq to study and evaluate the shallow Qaiyarah oil field in Iraq and with Ecopetrol S.A., a public company wholly owned by the Republic of Colombia, for a study of the heavy crude oil from the Castilla and Chichimene oil fields in Colombia. The \$2.1 million of EOR investments, as at December 31, 2004, include feasibility studies and related costs associated with these memoranda of understanding and other project activities in these regions.

5. LONG TERM ASSETS

During 2004, the Company acquired a 15% equity interest in Ensyn Petroleum International Ltd. ("**EPIL**") and exclusive rights to use the proprietary Ensyn RTP™ Technology in key international markets in China, Mongolia, Iraq, Oman and all countries in South America except Venezuela. In these countries, the Company's rights were to be exclusive for an initial term of five years until January 2009, subject to extension if and when commercial plants are constructed. For each project the Company develops using the Ensyn RTP™ Technology in its exclusive territories, Ensyn could elect to receive an equity participation in the project for the same proportionate cost the Company paid. The participation that may be obtained by Ensyn could be no more than 10%, except for each such project that the Company develops in South America, other than in Peru, where Ensyn could elect to receive an equity interest equal to 25% of the Company's interest. Ensyn's equity position would offset and eliminate the payment of license fees for use of the Ensyn RTP™ Technology in the project.

In December 2004, the Company and Ensyn Group Inc. ("**Ensyn**"), the parent company of EPIL, announced the signing of a merger agreement ("**Merger Agreement**") in which Ensyn will be merged with the Company ("**Merger**") and Ensyn will become a wholly owned subsidiary of the Company. With this Merger, the Company will gain full ownership of EPIL and its advanced upgrading technology for the development of heavy oil reserves around the world. Ensyn will spin-off its existing biomass processing business to its shareholders prior to the closing of this transaction.

Under the Merger Agreement, the Company will acquire all of the outstanding shares of Ensyn and all of the unissued shares of Ensyn common stock issuable upon the future exercise of any purchase warrants that remain unexercised when the Merger takes effect in exchange for \$10 million in cash and the issuance of Company common shares. The number of Company common shares to be issued will be based on the weighted, 10-day average of the Company's closing share price on the NASDAQ SmallCap market prior to the approval of the transaction by Ensyn shareholders. A minimum of 30 million Company common shares will be issued (See Note 17).

The Boards of Directors of both Ivanhoe and Ensyn have approved the Merger. The Merger will require the approval of Ensyn shareholders and may require the approval of the Company's shareholders, depending on the number of Company common shares required to be issued. The Merger is also subject to applicable regulatory approvals and other closing conditions customary in transactions of this nature.

As at December 31, 2004, the costs to acquire the 15% equity interest in EPIL of \$3.0 million plus \$2.5 million of costs incurred by the Company associated with the Merger are included in long term assets.

6. NOTES AND ADVANCE PAYABLE

In February 2003, the Company obtained a bank facility for up to \$5.0 million to develop the southern expansion of its South Midway field. The note is repayable over three years starting August 2004 with interest at 0.5% above the bank's prime rate or 3.0% over the London Inter-Bank Offered rate ("**LIBOR**"), at the option of the Company. The note is secured by all the Company's rights and interests in the South Midway properties. The note balance, as at December 31, 2004 and 2003, was \$4.3 million and \$1.0 million, respectively, with a six-month fixed LIBOR rate of 5.25% as at December 31, 2004.

The scheduled maturities of the bank note payable as at December 31, 2004 were as follows:

2005	$ 1,667
2006	1,667
2007	972
	4,306
Less: current portion	1,667
	$ 2,639

In March 2004, the Company received a $10.0 million advance as part of the $20.0 million up-front payment due from Richfirst for their farm-in to the Dagang field (See Note 4). Upon finalization of the farm-in agreement in June 2004, Richfirst elected to apply $10.0 million of the up-front payment due to the Company against the advance.

The Company borrowed $1.25 million from a related party at U.S. prime plus 3%. The unsecured loan was repaid with accrued interest in September 2003. The Company negotiated a revolving credit facility of $1.25 million to re-establish or extend that loan in the future as needs arise.

The Company has a stand-by loan facility for $6.0 million payable with interest at 8% per annum upon the earliest of i.) five days following receipt of proceeds from a private placement or public offering of Company common shares ii.) ninety days following written demand for repayment from lender or iii.) August 23, 2005. As at December 31, 2004, the Company had not made a drawdown under the loan (See Note 18).

7. ASSET RETIREMENT OBLIGATION

Effective January 2003, the Company changed its policy on accounting for liabilities associated with site restoration and abandonment of its oil and gas properties. The undiscounted amount of expected cash flows required to settle the asset retirement obligations as at December 31, 2004 was estimated at $1.4 million to be settled over a twelve-year period starting in 2010. The liability for the expected cash flows, as reflected in the financial statements, has been discounted from 5% to 7%. Implementation of the policy resulted in an additional provision for asset retirement of $0.2 million. For the years ended December 31, 2004 and 2003, $0.2 million and $0.1 million, respectively, were added to the carrying amount of the asset retirement obligations related to the restoration and abandonment of the Company's U.S. oil and gas properties as follows:

Balance as at December 31, 2002	$ 243
Cumulative effect of change in accounting policy	155
Accretion of liability	31
Additions	92
Balance as at December 31, 2003	521
Accretion of liability	48
Additions	180
Balance as at December 31, 2004	$ 749

8. SHARE CAPITAL

The authorized capital of the Company consists of an unlimited number of common shares without par value and an unlimited number of preferred shares without par value.

Private Placements and Share Purchase Warrants

Under a private placement in 2002, the Company issued 5.0 million common shares at $2.00, for net proceeds of $10.0 million.

In 2004 and 2003, the Company closed six special warrant financings for net proceeds of $20.4 million and $24.1 million, respectively, to advance its worldwide exploration and production, EOR and GTL activities, to pay down or restructure certain business indebtedness and for general working capital purposes. The financings consisted of 17,951,826 special warrants from $1.00 to $4.00 per special warrant. Each special warrant entitles the holder to acquire one common share and one common-share purchase warrant, at no additional cost. The net proceeds from the special warrant financings have been apportioned to the common shares. No amounts have been apportioned to the purchase warrants. The purchase warrants are exercisable to purchase additional common shares through the anniversary dates of the special warrant financing at the price per share as indicated in the following table:

Year of Special Warrant Financing	Price per Special Warrant (U.S.$)	Number of Purchase Warrants Issued	Remaining Number of Purchase Warrants	Number of Equivalent Common Shares	First Anniversary Date	First Anniversary Price per Share (U.S.$)	Second Anniversary Date	Second Anniversary Price per Share (U.S.$)
			(thousands)					
2003	$1.00	3,000	3,000	1,500	-	-	July 3, 2005	$1.10
2003	$1.00	3,000	3,000	1,500	-	-	August 18, 2005	$1.10
2003	$1.70	3,529	3,029	1,515	-	-	August 21, 2005	$1.87
2003	$4.00	1,250	1,250	1,250	-	-	October 31, 2005	$4.30
2004	$2.90	5,449	5,449	2,725	February 18, 2005	$3.00	February 18, 2006	$3.20
2004	$2.90	1,724	1,724	862	March 5, 2005	$3.00	March 5, 2006	$3.20
		17,952	17,452	9,352				

In November 2003, 500 thousand purchase warrants for $1.70 per share were exercised for the purchase of 250 thousand common shares.

Convertible Debenture

In June 2003, the $1.0 million unsecured convertible debenture was converted into two million of the Company's common shares at $0.50 per share. All accrued interest on the debenture was paid as of the conversion date.

Share Purchase Loans

In 1999 and 2001, the Company loaned $0.4 million to an employee and two directors to facilitate their exercise of stock options and warrants to purchase 165 thousand common shares of the Company. The Company held the shares as collateral for the loans. The loan balances were previously netted against the share capital balances. In December 2002, the Company determined the loans would not be renewed when they became due in December 2002 and January 2003. Each of the borrowers authorized the Company to acquire the shares held as collateral in full payment of their loan amounts and accrued interest, thereon. Subsequently, the Company eliminated the loans and retired the 165 thousand common shares at the average price of all common shares then issued and outstanding ($0.96 per share) and recorded a $0.25 million loss to retained earnings.

9. STOCK BASED COMPENSATION

The Company has an Employees' and Directors' Equity Incentive Plan under which it can grant stock options to directors and employees to purchase common shares, issue common shares to directors and employees for bonus awards and issue shares under a share purchase plan for employees.

Stock options are issued at not less than the quoted market value on the date of the grant and are conditional on continuing employment. Expiration and vesting periods are set at the discretion of the Board of Directors. Stock options granted prior to March 1, 1999 vested over a two-year period and expire ten years from date of issue. Stock options granted after March 1, 1999 vest over four years and expire five to ten years from the date of issue.

Following is a summary of the stock option portion of the Company's Equity Incentive Plan, including changes during the years ended:

	December 31, 2004		December 31, 2003		December 31, 2002	
	Number of Stock Options (thousands)	Weighted-Average Exercise Price (Cdn.$)	Number of Stock Options (thousands)	Weighted-Average Exercise Price (Cdn.$)	Number of Stock Options (thousands)	Weighted-Average Exercise Price (Cdn.$)
Outstanding at beginning of year	8,949	$2.64	10,265	$2.69	8,635	$2.66
Granted	608	$2.52	840	$4.95	2,095	$2.86
Exercised	(975)	$2.43	(1,363)	$3.39	(164)	$1.57
Cancelled/forfeited	(336)	$2.96	(793)	$4.42	(301)	$3.48
Outstanding at end of year	8,246	$2.65	8,949	$2.64	10,265	$2.69
Options exercisable at end of year	6,698	$2.44	6,974	$2.20	7,122	$2.13

The Company accounts for all stock options granted using the fair value based method of accounting. This method was adopted retroactively effective January 1, 2004 for stock options granted to employees and directors after January 1, 2002. Under this method, compensation costs are recognized in the financial statements over the stock options' vesting period using an option-pricing model for determining the fair value of the stock options at the grant date. The Company estimates a 20% forfeiture rate for stock options for purposes of calculating the fair value on the date stock options are granted. Revisions in forfeiture estimates are reflected as a change in accounting estimate in the period in which the revision occurs.

The effect of the accounting change on the net loss, as previously reported, for the years ended December 31, 2003 and 2002, was an increase of $0.5 million and $0.3 million, respectively. There is negligible effect on the net loss per share for the periods as previously reported. The accumulated deficit, as previously reported, as at the beginning of each of the years ended December 31, 2004 and 2003 has increased $0.8 million and $0.3 million, respectively, to reflect the retroactive adoption of the fair value based method of accounting for stock options granted to employees and directors after January 1, 2002. Additionally, 0.3 million stock options granted to employees and directors after January 1, 2002 were exercised during 2003 resulting in a $0.3 million increase in share capital as at December 31, 2003, as previously reported, with a corresponding reduction in contributed surplus. For the year ended December 31, 2004, the Company expensed $1.3 million for stock based compensation, which is included in the results of operations.

The foregoing is calculated in accordance with Black-Scholes options pricing model. The weighted average grant-date fair value of stock options granted during 2004, 2003 and 2002 was Cdn.$1.95, Cdn.$3.99 and Cdn.$1.65, respectively. The fair value of the stock options granted is estimated with the following weighted average assumptions for the years presented:

Assumptions used:	2004	2003	2002
Risk-free interest rate	4.0%	4.1%	4.4%
Dividend yield	0.0%	0.0%	0.0%
Volatility factor	107.6%	99.4%	72.0%
Expected life (years)	4.0	4.0	4.0

The following table summarizes information respecting stock options outstanding and exercisable as at December 31, 2004:

	Stock Options Outstanding			**Stock Options Exercisable**	
Range of Exercise Prices	**Number Outstanding**	**Weighted-Average Remaining Contractual Life**	**Weighted-Average Exercise Price**	**Number Exercisable**	**Weighted-Average Exercise Price**
(Cdn.$)	**(thousands)**	**(Years)**	**(Cdn.$)**	**(thousands)**	**(Cdn.$)**
$0.50 to $2.00	4,347	3.7	$0.65	4,031	$0.56
$2.60 to $3.60	1,651	3.0	$3.09	860	$3.14
$5.35 to $7.60	2,248	1.7	$6.17	1,807	$6.28
$0.50 to $7.60	8,246	3.0	$2.65	6,698	$2.44

10. RETIREMENT PLAN

In 2001, the Company adopted a defined contribution retirement or thrift plan ("**401(k) Plan**") to assist U.S. employees in providing for retirement or other future financial needs. Employees' contributions (up to the maximum allowed by U.S. tax laws) are matched 50% by the Company in 2001 and increasing 10% per year thereafter to a maximum of 100%. The Company's matching contributions to the 401(k) Plan were $0.2 million for each of the years ended December 31, 2004 and 2003 and $0.1 million for the year ended December 31, 2002.

11. SEGMENT INFORMATION

The Company has three reportable business segments: Oil and Gas, GTL and EOR.

Oil and Gas

The Company explores for, develops and produces crude oil and natural gas in the U.S. and in China. In the U.S., the Company's exploration, development and production activities are primarily conducted in California and Texas. In China, the Company's development and production activities are conducted at the Dagang oil field located in Hebei Province and exploration activities in the Zitong block located in Sichuan Province.

GTL

The Company holds a master license from Syntroleum to use its proprietary GTL technology to convert natural gas into synthetic

fuels. The master license allows the Company to use Syntroleum's proprietary process in an unlimited number of GTL projects throughout the world to convert natural gas into an unlimited volume of ultra clean transportation fuels and other synthetic petroleum products. The Company does not currently own or operate any GTL projects but has entered into agreements to study the feasibility of GTL plants in Egypt and Bolivia.

EOR

The Company seeks projects requiring relatively low initial capital outlays to which it can apply innovative technology and enhanced recovery techniques in developing them. The Company has exclusive rights to use the proprietary Ensyn RTP™ Technology in key international markets in China, Mongolia, Iraq, Oman and all countries in South America except Venezuela. In 2004, the Company entered into memoranda of understanding to evaluate the potential response of specific fields in Iraq and Colombia to the latest in EOR techniques and to determine the value that could be added to these fields using the Ensyn RTP™ Technology.

The Company maintains a corporate office in Canada with its operational office in the U.S. For this note, any amounts for the corporate office in Canada are included in Corporate. The accounting policies of the segments are the same as those disclosed in Note 2.

	Year ended December 31, 2004					
	Oil and Gas					
	U.S.	China	GTL	EOR	Corporate	Total
Oil and gas revenue	$ 9,311	$ 8,484	$ -	$ -	$ -	$ 17,795
Interest income	10	16	-	-	176	202
	9,321	8,500	-	-	176	17,997
Operating costs	3,159	1,914	-	-	-	5,073
General and administrative	990	960	1,471	442	5,325	9,188
Depletion and depreciation	4,594	2,864	16	4	4	7,482
Interest expense	195	-	-	-	184	379
Write-downs and provision for impairment	16,350	-	250	-	-	16,600
	25,288	5,738	1,737	446	5,513	38,722
Net (Income) Loss	$ 15,967	$ (2,762)	$ 1,737	$ 446	$ 5,337	$ 20,725
Capital Investments	$ 17,428	$ 26,965	$ 95	$ 1,966	$ -	$ 46,454
Identifiable Assets (As at December 31, 2004)	$ 49,465	$ 44,960	$ 13,867	$ 2,441	$ 7,753	$ 118,486

	Year ended December 31, 2003 (as restated, see Notes 2 and 9)					
	Oil and Gas					
	U.S.	China	GTL	EOR	Corporate	Total
Oil and gas revenue	$ 5,466	$ 4,103	$ -	$ -	$ -	$ 9,569
Interest income	19	-	-	-	71	90
	5,485	4,103	-	-	71	9,659
Operating costs	2,313	1,980	-	-	-	4,293
General and administrative	2,109	1,176	1,331	-	3,595	8,211
Depletion and depreciation	2,321	1,484	20	-	4	3,829
Interest expense	115	27	-	-	42	184
Write-down and provision for impairment	20,000	-	3,321	-	-	23,321
	26,858	4,667	4,672	-	3,641	39,838
Net Loss	$ 21,373	$ 564	$ 4,672	$ -	$ 3,570	$ 30,179
Capital Investments	$ 8,386	$ 6,213	$ 792	$ -	$ -	$ 15,391
Identifiable Assets (As at December 31, 2003)	$ 47,650	$ 30,766	$ 14,181	$ -	$ 13,977	$ 106,574

	Oil and Gas U.S.	Oil and Gas China	GTL	EOR	Corporate	Total
	Year ended December 31, 2002 (as restated, see Notes 2 and 9)					
Oil and gas revenue	$ 5,099	$ 3,230	$ -	$ -	$ -	$ 8,329
Interest income	6	1	-	-	101	108
	5,105	3,231	-	-	101	8,437
Operating costs	2,351	1,490	-	-	-	3,841
General and administrative	1,178	905	675	-	3,197	5,955
Depletion and depreciation	2,090	1,206	13	-	3	3,312
Interest expense	2	21	-	-	-	23
Write-down and provision for impairment	-	-	2,436	-	-	2,436
	5,621	3,622	3,124	-	3,200	15,567
Net Loss	$ 516	$ 391	$ 3,124	$ -	$ 3,099	$ 7,130
Capital Investments	$ 13,305	$ 3,626	$ 1,897	$ -	$ -	$ 18,828
Identifiable Assets (As at December 31, 2002)	$ 62,922	$ 25,620	$ 17,111	$ -	$ 1,435	$ 107,088

12. DERIVATIVE ACTIVITIES

The Company's results of operations are sensitive mainly to fluctuations in oil and natural gas prices. The Company may periodically use different types of derivative instruments to manage its exposure to price volatility, thus mitigating fluctuations in commodity-related cash flows.

The Company entered into costless collar derivatives to hedge its cash flow from the sale of 500 barrels of oil production per day over two six-month periods starting October 2002 and June 2003. The derivatives had ceiling prices of $30.45 and $28.95 per barrel for the June 2003 and October 2002 contracts, respectively, and a floor price of $24.00 per barrel using WTI as the index traded on the NYMEX. Gains and losses on derivatives were recognized in the results of operations as realized. For the year ended December 31, 2003, the Company had realized losses of $0.3 million on derivative transactions. The Company had insignificant realized derivative losses for the year ended December 31, 2002. The derivative losses are included in oil and gas revenue.

For the year ended December 31, 2004 the Company had no hedging activity. There were no hedge contracts outstanding as at December 31, 2004 and 2003.

13. PROVISION FOR IMPAIRMENT

The Company impaired its U.S. oil and gas properties $16.3 million in 2004 due to the evaluation of a number of its unproved properties, primarily in California, plus the impairment of its producing fields at Knights Landing, Citrus and the southern expansion at South Midway as costs incurred to add new reserves exceeded the expected future cash flows from those properties. Prices used in calculating the expected future cash flows were based on the following benchmark prices adjusted for gravity, transportation and other factors as required by sales agreements:

	As at December 31, 2004 West Texas Intermediate (per Bbl)	Henry Hub (per Mcf)
2005	$42.00	$6.20
2006	$40.00	$6.00
2007	$38.00	$5.75
2008	$36.00	$5.50
2009	$34.00	$5.50
2010 to 2015	$33.00 to $34.50	$5.50 to $5.75
Thereafter	2% per year	2% per year

The $20.0 million provision for impairment for 2003 is due mainly to an increase in the carrying costs of the Company's evaluated U.S. oil and gas properties primarily in East Texas, Northwest Lost Hills and other California prospects when compared to the estimated recoverable value of its U.S. proved reserves as at December 31, 2003. Such carrying costs increased as a result of the decision, in the fourth quarter of 2003, to potentially farm-out up to 50% of the Company's working interest to one or more partners to fund a test of Northwest Lost Hills # 1-22. Additionally, evaluation of significant portions of the Company's acreage positions in East Texas and the southern San Joaquin Basin in California was completed in 2003 and either have been, or will be, relinquished, thus adding to the carrying value of the Company's evaluated U.S. oil and gas properties. Prices used in calculating the expected future

cash flows were based on the following benchmark prices adjusted for gravity, transportation and other factors as required by sales agreements:

	As at December 31, 2003	
	West Texas Intermediate (per Bbl)	Henry Hub (per Mcf)
2004	$29.00	$5.10
2005	$26.00	$4.50
2006	$25.00	$4.35
2007	$25.00	$4.35
2008	$25.00	$4.35
2009 to 2014	$25.00	$4.35
Thereafter	1.5% per year	1.5% per year

14. INCOME TAXES

The Company and its subsidiaries are required to individually file tax returns in each of the jurisdictions in which they operate. The provision for income taxes differs from the amount computed by applying the statutory income tax rate to the net losses before income taxes. The statutory rate as at December 31, 2004 was 33.6% and 43.2% as at December 31, 2003 and 2002. The sources and tax effects for the differences were as follows:

	As at December 31,		
	2004	2003	2002
Tax benefit computed at the combined Canadian federal and provincial statutory income tax rates	$ (6,968)	$ (12,832)	$ (2,946)
Effect of change in effected income tax rates on future tax assets	(488)	-	-
Foreign net losses affected at lower income tax rates	(246)	3,251	1,411
Expiry of tax loss carry-forwards	977	569	125
Effect of change in foreign exchange rates	(3,433)	(522)	-
Stock-based compensation not deductible for income tax purposes	375	-	-
Tax credit carry-forward	(1,094)	-	-
Change in prior year estimate of tax loss carry-forwards	1,756	(239)	(3,090)
Permanent differences related to U.S. royalty interests acquired	1,250	710	-
Other	(5)	170	(25)
	(7,876)	(8,893)	(4,525)
Valuation allowance	7,876	8,893	4,525
	$ -	$ -	$ -

Significant components of the Company's future net income tax assets as at December 31 were as follows:

	2004		2003	
	Future Income Tax		Future Income Tax	
	Assets	Liabilities	Assets	Liabilities
Oil and gas properties and investments	$ -	$ (11,560)	$ -	$ (8,393)
Tax loss carry-forwards	58,842	-	48,893	-
Tax credit carry-forward	1,094	-	-	-
Valuation allowance	(48,376)	-	(40,500)	-
	$ 11,560	$ (11,560)	$ 8,393	$ (8,393)

Due to the uncertainty of utilizing these net income tax assets, the Company has made a valuation allowance of an equal amount against the potential recoverable amounts.

The tax loss carry-forwards in Canada are Cdn. $43.2 million and in the U.S. $73.5 million. The tax loss carry-forwards in Canada expire between 2005 and 2011 and in the U.S. between 2018 and 2024. In China, the Company has available for carry-forward against future Chinese income $49.2 million of cost basis. The loss of approximately Cdn. $55.3 million from the Russian operations in 2000, being the aggregate investment, not including accounting write-downs, less proceeds received on settlement is a capital loss for Canadian income tax purposes, available for carry-forward against future Canadian capital gains indefinitely and is not included in the future income tax assets above.

15. NET LOSS PER SHARE

Had the Company generated net earnings during the years presented, the earnings per share calculations for the years presented would

have included the following weighted average items:

	Year ended December 31, (thousands of shares)		
	2004	2003	2002
Warrants	2,107	556	-
Convertible debenture	-	499	1,299
Stock options	3,796	3,535	2,986
	5,903	4,590	4,285

Additionally, the earnings per share calculations would not have included the following weighted average items because the exercise prices exceeded the average market prices of the common shares:

	Year ended December 31, (thousands of shares)		
	2004	2003	2002
Warrants	4,082	140	-
Convertible debenture	-	306	-
Stock options	3,669	3,802	5,359
	7,751	4,248	5,359

16. RELATED PARTY TRANSACTIONS

The Company has entered into agreements with a number of entities, some of which are related through common directors or shareholders, to share administrative personnel, aircraft, office space and facilities. The agreement for the usage of aircraft was terminated in 2003. The Company is billed on a cost recovery basis. The costs incurred in the normal course of business with respect to the above arrangements amounted to $0.9 million for each of the years ended December 31, 2004 and 2003 and $1.2 million for the year ended December 31, 2002. In addition, a company controlled by a director provides consulting services to the Company. Consulting services and out of pocket expenses paid to this company were $0.7 million for the year ended December 31, 2004 and $0.4 million for each of the years ended December 31, 2003 and 2002. As at December 31, 2004 and 2003, amounts included in accounts payable under these arrangements were $0.1 million.

The Company borrowed $1.25 million from a related company controlled by a director of the Company. The loan, plus accrued interest, was repaid in September 2003 (See Note 6).

17. COMMITMENTS AND CONTINGENCIES

Zitong Exploration Commitment

With the signing of the production-sharing contract in September 2002 for the Zitong block, the Company is obligated to conduct a minimum exploration program during the first three years, which will include acquiring seismic data, reprocessing existing seismic and drilling two exploration wells. At the end of the three-year period, if the Company does not complete the minimum exploration program, and elects not to continue, it will be obligated to pay, to CNPC within 30 days, a cash equivalent of the deficiency in the work program. The remaining cost of the minimum exploration program was estimated to be at least $12.4 million as at December 31, 2004.

Northwest Lost Hills Abandonment Contingency

The Company has temporarily abandoned Northwest Lost Hills #1-22 pending the identification of one or more partners to share the costs of the testing program. If the well were permanently abandoned, the Company would be obligated for its share of the costs to plug and abandon the well, which is estimated to be $1.1 million. There is no provision in the balance sheet for this contingent obligation.

Ensyn Acquisition

Under the Merger Agreement, the Company will pay $10 million in cash and issue Company common shares to acquire all the issued and outstanding common shares of Ensyn and all of the unissued shares of Ensyn common stock issuable upon the future exercise of any purchase warrants that remain unexercised when the Merger takes effect. The number of Company common shares to be issued will be the greater of (i) 30 million or (ii) the quotient obtained by dividing $75 million by the weighted average of the closing prices of the Company common shares on the NASDAQ SmallCap Market over a period of ten consecutive trading days determined five

business days prior to the meeting at which Ensyn's shareholders will be asked to approve the Merger. If the number of Company common shares to be issued exceeds 42.4 million Company common shares, then the Company shall be required to hold a meeting at which its shareholders will be asked to approve the issuance of the Company common shares. The Company may be required to pay Ensyn a termination fee of $2.75 million if it is required to hold a shareholders' meeting to approve the issuance of the Company common shares and decides not to or holds a required shareholders' meeting and the Company's shareholders do not approve such share issuance. Additionally, the Merger Agreement provides that the Company may be obligated, under certain circumstances, to reimburse up to $1.0 million of Ensyn's expenses related to the Merger.

Other Commitments

The Company may provide indemnifications, in the course of normal operations, that are often standard contractual terms to counterparties in certain transactions such as purchase and sale agreements. The terms of these indemnifications will vary based upon the contract, the nature of which prevents the Company from making a reasonable estimate of the maximum potential amounts that may be required to be paid. The Company's management is of the opinion that any resulting settlements relating to potential litigation matters or indemnifications would not materially affect the financial position of the Company.

Lease Commitments

For the years ended December 31, 2004, 2003 and 2002, the Company expended $0.5 million, $0.5 million and $0.6 million, respectively, on operating leases relating to the rental of office space, which expire between April 2005 and March 2010. Such leases frequently provide for renewal options and require the Company to pay for utilities, taxes, insurance and maintenance expenses. As at December 31, 2004, future net minimum lease payments for operating leases (excluding oil and gas and other mineral leases) were the following:

2005	$ 616
2006	543
2007	342
2008	287
2009	287
Thereafter	48
	$ 2,123

18. SUBSEQUENT EVENTS

In February 2005, the Company borrowed $6.0 million of the stand-by loan facility and amended the loan agreement to provide the lender the right to convert, at the lender's election, unpaid principal and interest during the loan term to the Company's common shares at $2.25 per share (See Note 6).

19. ADDITIONAL DISCLOSURES REQUIRED UNDER U.S. GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Company's consolidated financial statements have been prepared in accordance with GAAP as applied in Canada. In the case of the Company, Canadian GAAP conforms in all material respects with U.S. GAAP except for certain matters, the details of which are as follows:

Consolidated Balance Sheets

The application of U.S. GAAP has the following effects on balance sheet items as reported under Canadian GAAP:

Shareholders' Equity and Oil and Gas Properties and Investments

	As at December 31, 2004				
		Shareholders' Equity			
	Oil and Gas Properties and Investments	Share Capital	Contributed Surplus	Accumulated Deficit	Total
Canadian GAAP	$ 96,551	$ 183,617	$ 1,748	$ (81,779)	$ 103,586
Adjustment for reduction in stated capital	-	74,455	-	(74,455)	-
Adjustment to ascribed value of shares issued for U.S. royalty interests, net	1,358	1,358	-	-	1,358
Provision for impairment	(8,650)	-	-	(8,650)	(8,650)
Depletion adjustments due to differences in provision for impairment	482	-	-	482	482
GTL and EOR development costs expensed	(5,884)	-	-	(5,884)	(5,884)
Adjustment for change in accounting for stock based compensation	-	(300)	(1,660)	1,960	-
U.S. GAAP	$ 83,857	$ 259,130	$ 88	$ (168,326)	$ 90,892

	As at December 31, 2003				
		Shareholders' Equity			
	Oil and Gas Properties and Investments	Share Capital	Contributed Surplus	Accumulated Deficit	Total
Canadian GAAP	$ 87,956	$ 161,075	$ 516	$ (61,054)	$ 100,537
Adjustment for reduction in stated capital	-	74,455	-	(74,455)	-
Adjustment to ascribed value of shares issued for U.S. royalty interests, net	1,358	1,358	-		1,358
Provision for impairment	(10,000)	-	-	(10,000)	(10,000)
Depletion adjustments due to differences in provision for impairment	166	-	-	166	166
GTL and EOR development costs expensed	(4,074)	-	-	(4,074)	(4,074)
Adjustment for change in accounting for stock based compensation	-	(271)	(516)	787	-
U.S. GAAP	$ 75,406	$ 236,617	$ -	$ (148,630)	$ 87,987

Share Capital and Accumulated Deficit

In June 1999, the shareholders approved a reduction of stated capital in respect of the common shares by an amount of $74.4 million being equal to the accumulated deficit as at December 31, 1998. Under U.S. GAAP, a reduction of the accumulated deficit such as this is not recognized except in the case of a quasi reorganization. The effect of this is that under U.S. GAAP, share capital and accumulated deficit are increased by $74.4 million as at December 31, 2004 and 2003.

Oil and Gas Properties and Investments

Prior to January 2004, there were certain differences between the full cost method of accounting for oil and gas properties as applied in Canada and as applied in the U.S. The principal difference was in the method of performing ceiling test evaluations under the full cost method of accounting rules. Under Canadian GAAP prior to January 2004, impairment of oil and gas properties was based on the amount by which a cost center's carrying value exceeded its undiscounted future net cash flows from proved reserves using period-end, non-escalated prices and costs, less an estimate for future general and administrative expenses, financing costs and income taxes. As more fully described in Note 2 "Oil and Gas Properties", effective January 2004, Canadian GAAP requires recognition and measurement processes to assess impairment of oil and gas properties using estimates of future oil and gas prices and costs plus the cost of unproved properties that have been excluded from the depletion calculation. In the measurement of the impairment, the future net cash flows of a cost center's proved and probable reserves are discounted using a risk-free interest rate.

For U.S. GAAP purposes, future net cash flows from proved reserves using period-end, non-escalated prices and costs, are discounted to present value at 10% per annum and compared to the carrying value of oil and gas properties. The Company performed the ceiling test in accordance with U.S. GAAP and determined that for 2004 an impairment provision of $15.0 was required on its U.S. oil and gas properties compared to a $16.3 million impairment provision under Canadian GAAP. For 2001, a $10.0 million provision for impairment was required, for U.S. GAAP purposes, in connection with the Company's China oil and gas properties resulting in accumulated net additional impairment provisions of $8.7 million for U.S. GAAP purposes as at December 31, 2004. There was no difference in the impairment provisions for 2003 and no impairment provision was required for 2002 under Canadian or U.S. GAAP.

The differences in the amount of impairment provisions between Canadian and U.S. GAAP resulted in a reduction in accumulated depletion of $0.5 million and $0.2 million as at December 31, 2004 and 2003, respectively.

As more fully described under "Investments in EOR and GTL Projects" in Note 2, for Canadian GAAP the Company capitalizes certain costs incurred for GTL and EOR projects subsequent to executing an MOU to determine the technical and commercial feasibility of a project, including studies for the marketability for the projects' products. If no definitive agreement is reached, then the project's capitalized costs, which are deemed to have no future value, are written down and charged to operations with a corresponding reduction in the investments in GTL and EOR assets.

For U.S. GAAP, feasibility, marketing and related costs incurred prior to executing a GTL or EOR definitive agreement are considered to be research and development and are expensed as incurred. As at December 31, 2004 and 2003, the Company capitalized $5.9 million and $4.1 million, respectively, for Canadian GAAP, which was expensed for U.S. GAAP purposes.

For U.S. GAAP purposes, the aggregate value attributed to the acquisition of U.S. royalty rights during 1999 and 2000 was $1.4 million higher, due to the difference between Canadian and U.S. GAAP in the value ascribed to the shares issued, primarily resulting from differences in the recognition of effective dates of the transactions. For the year ended December 31, 2004, a ceiling test impairment of $1.0 million of the U.S. GAAP difference related to royalty rights was recognized in the results of operations.

Consolidated Statements of Loss

The application of U.S. GAAP had the following effects on net loss and net loss per share as reported under Canadian GAAP:

	Year ended December 31,					
	2004		2003		2002	
	Net Loss	Net Loss Per Share	Net Loss	Net Loss Per Share	Net Loss	Net Loss Per Share
Canadian GAAP (as restated for 2003 and 2002 see *Notes 2 and 9*)	$ 20,725	$ 0.12	$ 30,179	$ 0.20	$ 7,130	$ 0.05
Stock based compensation expense	(1,173)	(0.01)	(476)	-	(311)	-
Provision for impairment	(1,350)	(0.01)	-	-	-	-
Depletion adjustments due to differences in provision for impairment	(316)	-	(88)	-	(78)	-
GTL and EOR development costs expensed, net	1,810	0.02	(2,529)	(0.02)	1,461	0.01
U.S. GAAP	$ 19,696	0.12	$ 27,086	$ 0.18	$ 8,202	$ 0.06
Weighted Average Number of Shares under U.S. GAAP (in thousands)		167,612		150,154		142,314

As discussed under "Oil and Gas Properties and Investments" in this note, there is a difference in performing the ceiling test evaluation under the full cost method of accounting between U.S. and Canadian GAAP. Application of the ceiling test evaluation under U.S. GAAP for 2004, resulted in a lower impairment provision on the Company's U.S. oil and gas properties by $1.3 million and for 2001 required an additional $10.0 million provision for impairment with respect to the Company's China oil and gas properties. The net increase in impairment provisions resulted in lower depletion rates for U.S. GAAP purposes and a reduction of $0.3 million in the net loss for the year ended December 31, 2004 and $0.1 million reductions in the net losses for each of the years ended December 31, 2003 and 2002.

As more fully discussed under "Stock Based Compensation" in Notes 2 and 9, as of January 1, 2004 the Company changed its accounting policy, for Canadian GAAP, to recognize compensation costs using the fair value based method of accounting for stock options granted to employees and directors after January 1, 2002. For U.S. GAAP, the Company continues to apply APB Opinion No. 25, as interpreted by FASB Interpretation No. 44, in accounting for its stock option plan and does not recognize compensation costs in its financial statements for stock options issued to employees and directors. This resulted in a reduction of $1.2 million, $0.5 million and $0.3 million in the net losses for the years ended December 31, 2004, 2003 and 2002, respectively.

As more fully described under "Oil and Gas Properties and Investments" in this note, for Canadian GAAP, feasibility, marketing and related costs incurred prior to executing a GTL or EOR definitive agreement are capitalized and are subsequently written down upon determination that a project's future value has been impaired. For U.S. GAAP, such costs are considered to be research and development and are expensed as incurred. For the years ended December 31, 2004 and 2002, the Company expensed $1.8 million and $1.5 million, respectively, in excess of the Canadian GAAP write-downs during those corresponding years. For the year ended December 31, 2003, the Company expensed $2.5 million less for U.S. GAAP than the write-down recognized for Canadian GAAP.

Stock Based Compensation

Had stock based compensation expense been determined based on fair value at the stock option grant date, consistent with the method of SFAS No. 123, "Accounting for Stock Based Compensation", the Company's net loss and net loss per share would have been increased to the pro forma amounts indicated below:

	Year ended December 31,		
	2004	2003	2002
Net loss under U.S. GAAP	$ 19,696	$ 27,086	$ 8,202
Stock-based compensation expense determined under the fair value based method for employee and director awards	1,869	1,682	1,885
Pro forma net loss under U.S. GAAP	$ 21,565	$ 28,768	$ 10,087
Basic and diluted loss per common share under U.S. GAAP:			
As reported	$ 0.12	$ 0.18	$ 0.06
Pro forma	$ 0.13	$ 0.19	$ 0.07
Weighted Average Number of Shares under U.S. GAAP (in thousands)	167,612	150,154	142,314
Stock options granted during the period (thousands)	458	690	1,870
Weighted average exercise price	$ 1.88	$ 4.00	$ 1.92
Weighted average fair value of options granted during the year	$ 1.40	$ 2.83	$ 1.07

Stock based compensation for U.S. GAAP was calculated in accordance with the Black Scholes option-pricing model using the same assumptions as used for Canadian GAAP.

Consolidated Statements of Cash Flow

As a result of the write-down of GTL and EOR development costs required under U.S. GAAP, the statement of cash flow as reported would result in a cash surplus from operating activities of $2.0 million for the year ended December 31, 2004 and cash deficiencies from operating activities of $2.3 million and $4.0 million for the years ended December 31, 2003 and 2002, respectively. Additionally, capital investments reported under investing activities would be $44.4 million, $14.6 million and $16.9 million for the same periods ended, respectively.

Additional U.S. GAAP Disclosures

Oil and Gas Properties and Investments

The categories of costs included in "Oil and Gas Properties and Investments", including the U.S. GAAP adjustments discussed in this note were as follows:

	As at December 31, 2004				As at December 31, 2003			
	U.S.	China	GTL	Total	U.S.	China	GTL	Total
Property acquisition costs	$ 22,295	$ 2,418	$ -	$ 24,713	$ 17,518	$ 2,418	$ -	$ 19,936
Royalty rights acquired	10,582	-	-	10,582	10,582	-	-	10,582
Exploration costs	35,120	8,594	-	43,714	31,269	1,669	-	32,938
Development costs	35,456	35,105	-	70,561	27,068	28,587	-	55,655
GTL master license	-	-	10,000	10,000	-	-	10,000	10,000
Support equipment and general property	480	270	-	750	433	196	-	629
	103,933	46,387	10,000	160,320	86,870	32,870	10,000	129,740
Accumulated depletion and depreciation	(11,197)	(6,266)	-	(17,463)	(6,696)	(3,638)	-	(10,334)
Provision for impairment	(49,000)	(10,000)	-	(59,000)	(34,000)	(10,000)	-	(44,000)
	$ 43,736	$ 30,120	$ 10,000	$ 83,857	$ 46,174	$ 19,232	$ 10,000	$ 75,406

U.S. development costs as at December 31, 2004 and 2003 include $0.6 million and $0.4 million, respectively, of asset retirement costs.

As at December 31, 2004, the costs of unproved properties included in oil and gas properties were as follows:

	Total	2004	2003	2002	Prior to 2002
		Incurred in			
Property Acquisition	$ 8,973	$ 893	$ 673	$ 2,055	$ 5,352
Royalty rights	6,851	-	-	-	6,851
Exploration	15,592	8,949	1,877	-	4,766
	$ 31,416	$ 9,842	$ 2,550	$ 2,055	$ 16,969

The difference from Canadian GAAP in unproved oil and gas properties as at December 31, 2004 was $0.4 million related to the $1.4 million of aggregate value attributed to the acquisition of U.S. royalty rights during 1999 and 2000 less a $1.0 million ceiling test impairment associated with these royalty rights recognized for U.S. GAAP during the year ended December 31, 2004.

Accounts Payable and Accrued Liabilities

The following was the breakdown of accounts payable and accrued liabilities:

	As at December 31, 2004	2003
Accounts payable and accruals	$ 8,745	$ 3,626
Accrued salaries and related expenses	929	858
Accrued interest	11	2
Other accruals	160	30
	$ 9,845	$ 4,516

Impact of New and Pending U.S. GAAP Accounting Standards

In June 2004, the Financial Accounting Standards Board ("**FASB**") issued an exposure draft of a proposed statement, "Fair Value Measurements" to provide guidance on how to measure the fair value of financial and non-financial assets and liabilities when required by other authoritative accounting pronouncements. The proposed statement attempts to address concerns about the ability to develop reliable estimates of fair value and inconsistencies in fair value guidance provided by current U.S. GAAP, by creating a framework that clarifies the fair value objective and its application in GAAP. In addition, the proposal expands disclosures required about the use of fair value to re-measure assets and liabilities. The standard would be effective for financial statements issued for fiscal years beginning after June 15, 2005.

In September of 2004, the SEC released Staff Accounting Bulletin No. 106, which provides guidance regarding the interaction of Statement of Financial Accounting Standard No. 143, Accounting for Asset Retirement Obligations ("**SFAS 143**") with the full cost accounting rules in Article 4-10 of Regulation S-X. This bulletin clarifies the treatment of assets and liabilities resulting from the implementation of SFAS 143 on the full cost ceiling test and the calculation of depletion, depreciation and amortization. The Company is in compliance with the provisions of Staff Accounting Bulletin No. 106.

In December 2004, the FASB issued a revision to SFAS No, 123, "Accounting for Stock Based Compensation" which supersedes APB No. 25, "Accounting for Stock Issued to Employees". This Statement requires measurement of the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the date of the grant and recognition of the cost in the results of operations over the period during which an employee is required to provide service in exchange for the award. No compensation cost is recognized for equity instruments for which employees do not render the requisite service. The Company applies APB Opinion No. 25, as interpreted by FASB Interpretation No. 44, in accounting for awards issued from our stock option plan and do not recognize compensation costs in our U.S. GAAP financial statements for stock options issued to its employees and directors. This statement is effective for the first interim or annual reporting that begins after June 15, 2005 and maybe implemented on a modified prospective or retrospective basis. The Company has elected to implement this statement on a modified prospective basis starting in the third quarter of 2005. Under the modified prospective basis the Company would recognize stock based compensation in its U.S. GAAP results of operations for the unvested portion of awards outstanding as of July 1, 2005 and for all awards granted after July 1, 2005.

The following standards issued by the FASB do not impact the Company at this time:

SFAS No. 151, "Inventory Costs—an amendment of ARB No. 43, Chapter 4" effective for inventory costs incurred during fiscal years beginning after June 15, 2005.

SFAS No. 153, "Exchanges of Nonmonetary Assets—an amendment of APB Opinion No. 29" effective for nonmonetary asset exchanges occurring in fiscal years beginning after June 15, 2005.

QUARTERLY FINANCIAL DATA IN ACCORDANCE WITH CANADIAN AND U.S. GAAP (UNAUDITED)

	QUARTER ENDED							
	2004				2003			
	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr
Total revenue	$ 6,212	$ 4,932	$ 3,521	$ 3,332	$ 2,330	$ 2,423	$ 2,338	$ 2,568
Net loss - Canadian GAAP	$ 17,184	$ 951	$ 1,298	$ 1,292	$ 23,154	$ 1,330	$ 4,587	$ 1,108
Net loss - U.S. GAAP	$ 15,736	$ 980	$ 1,510	$ 1,470	$ 23,270	$ 1,306	$ 1,325	$ 1,185
Net loss per share - Canadian GAAP	$ 0.09	$ 0.01	$ 0.01	$ 0.01	$ 0.15	$ 0.01	$ 0.03	$ 0.01
Net loss per share - U.S. GAAP	$ 0.09	$ 0.01	$ 0.01	$ 0.01	$ 0.15	$ 0.01	$ 0.01	$ 0.01

The 2003 quarterly earnings for Canadian GAAP have been restated to give effect to the retroactive application of CICA Section 3870 – "Stock Based Compensation and Other Stock Based Payments", which is more fully described in Note 2 under "Stock Based Compensation". The net losses in the fourth quarter of 2004, for Canadian and U.S. GAAP, were primarily due to impairment provisions of $16.3 million and $15.0 million, respectively, for U.S. oil and gas properties. The net losses in the fourth quarter of 2003, for both Canadian and U.S. GAAP, were primarily due to an impairment provision of $20.0 million for U.S. oil and gas properties. The net loss under Canadian GAAP for the second quarter of 2003 included a $3.3 million write-down of costs associated with the unsuccessful negotiations of a GTL contract in Qatar. For U.S. GAAP, these costs are expensed as they are incurred

SUPPLEMENTARY DISCLOSURES ABOUT OIL AND GAS PRODUCTION ACTIVITIES (UNAUDITED)

The following information about the Company's oil and gas producing activities is presented in accordance with U.S. Statement of Financial Accounting Standards No. 69, "Disclosures About Oil and Gas Producing Activities".

Oil and Gas Reserves

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic conditions.

Proved developed oil and gas reserves are reserves, which can be expected to be recovered from existing wells with existing equipment and operating methods.

Estimates of oil and gas reserves are subject to uncertainty and will change as additional information regarding the producing fields and technology becomes available and as future economic conditions change.

Reserves presented in this section represent the Company's share of reserves, excluding royalty interests of others. The reserves for 2004 and 2003 in the U.S. were based on the estimates by the independent petroleum engineering firm of Netherland, Sewell & Associates, Inc. The reserves for 2002 in the U.S. were based on estimates by the independent petroleum engineering firms of Joe C. Neal & Associates and Allan Spivak Engineering. In China, the reserves were based on estimates by the independent petroleum engineering firm of Gilbert Laustsen Jung Associates Ltd.

The Company's net proved and net proved developed oil and gas reserves were as follows:

	Oil (MBbl)			Gas (MMcf)
	U.S.	China	Total	U.S.
Net proved reserves, December 31, 2001	2,003	21,795	23,798	1,631
Extensions and discoveries	710	-	710	63
Production	(208)	(142)	(350)	(103)
Revisions to previous estimates	(280)	(2,601)	(2,881)	(101)
Sales of reserves	(441)	(3,448)	(3,889)	(671)
Net proved reserves, December 31, 2002	1,784	15,604	17,388	819
Extensions and discoveries	480	-	480	22
Production	(202)	(144)	(346)	(50)
Revisions to previous estimates	(499)	239	(260)	(96)
Net proved reserves, December 31, 2003	1,563	15,699	17,262	695
Extensions and discoveries	240	-	240	1,289
Purchases of reserves in place	-	-	-	819
Production	(234)	(235)	(469)	(207)
Revisions to previous estimates	(121)	(1,360)	(1,481)	87
Sale of reserves	(18)	(6,196)	(6,214)	-
Net proved reserves, December 31, 2004	1,430	7,908	9,338	2,683
Net proved developed reserves:				
December 31, 2002	1,131	48	1,179	819
December 31, 2003	1,225	209	1,434	695
December 31, 2004	1,187	1,142	2,329	2,365

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves

The following standardized measure of discounted future net cash flows from proved oil and gas reserves was computed using period end statutory tax rates, costs and prices of $40.25, $30.31 and $29.04 per barrel of oil in 2004, 2003 and 2002, respectively, and $5.94, $6.13 and $5.30 per Mcf of gas in 2004, 2003 and 2002, respectively. A discount rate of 10% was applied in determining the standardized measure of discounted future net cash flows.

The Company does not believe that this information reflects the fair market value of its oil and gas properties. Actual future net cash flows will differ from the presented estimated future net cash flows in that:

- future production from proved reserves will differ from estimated production;
- future production will also include production from probable and potential reserves;
- future, rather than year end, prices and costs will apply; and
- existing economic, operating and regulatory conditions are subject to change.

The standardized measure of discounted future net cash flows as at December 31 in each of the three most recently completed financial years were as follows:

	2004		
	U.S.	China	Total
Future cash inflows	$ 64,357	$ 327,481	$ 391,838
Future development and restoration costs	3,063	84,682	87,745
Future production costs	27,867	58,488	86,355
Future income taxes	-	44,708	44,708
Future net cash flows	33,427	139,603	173,030
10% annual discount	11,238	50,774	62,012
Standardized measure	$ 22,189	$ 88,829	$ 111,018

	2003		
	U.S.	China	Total
Future cash inflows	$ 48,751	$ 478,748	$ 527,499
Future development and restoration costs	2,138	154,245	156,383
Future production costs	22,037	91,912	113,949
Future income taxes	-	61,647	61,647
Future net cash flows	24,576	170,944	195,520
10% annual discount	7,466	89,180	96,646
Standardized measure	$ 17,110	$ 81,764	$ 98,874

	2002		
	U.S.	China	Total
Future cash inflows	$ 52,057	$ 461,256	$ 513,313
Future development and restoration costs	4,597	129,855	134,452
Future production costs	16,288	134,540	150,828
Future income taxes	-	52,656	52,656
Future net cash flows	31,172	144,205	175,377
10% annual discount	9,687	84,423	94,110
Standardized measure	$ 21,485	$ 59,782	$ 81,267

Changes in standardized measure of discounted future net cash flows as at December 31 in each of the three most recently completed financial years were as follows:

	2004		
	U.S.	China	Total
Sale of oil & gas net of production costs	$ (6,152)	$ (6,570)	$ (12,722)
Net changes in pricing and production costs	1,015	56,329	57,344
Sale of reserves	(108)	(21,646)	(21,754)
Discoveries and extensions	6,779	-	6,779
Purchases of reserves in place	3,050	-	3,050
Revisions of previous estimates	(1,401)	(22,847)	(24,248)
Net change in income taxes	-	(9,107)	(9,107)
Net change in future development costs	(1,700)	(14,424)	(16,124)
Accretion of discount	3,596	25,330	28,926
Increase (decrease)	5,079	7,065	12,144
Standardized measure, beginning of year	17,110	81,764	98,874
Standardized measure, end of year	$ 22,189	$ 88,829	$ 111,018

	2003		
	U.S.	China	Total
Sale of oil & gas net of production costs	$ (3,153)	$ (2,123)	$ (5,276)
Net changes in pricing and production costs	(4,034)	47,960	43,926
Discoveries and extensions	5,712	(636)	5,076
Revisions of previous estimates	(8,957)	1,604	(7,353)
Net change in income taxes	-	(9,435)	(9,435)
Net change in future development costs	2,337	(14,626)	(12,289)
Accretion of discount	3,720	(762)	2,958
Increase (decrease)	(4,375)	21,982	17,607
Standardized measure, beginning of year	21,485	59,782	81,267
Standardized measure, end of year	$ 17,110	$ 81,764	$ 98,874

	2002		
	U.S.	China	Total
Sale of oil & gas net of production costs	$ (2,748)	$ (1,740)	$ (4,488)
Net changes in pricing and production costs	13,700	150,510	164,210
Sale of reserves	(4,192)	(43,493)	(47,685)
Discoveries and extensions	10,135	(550)	9,585
Revisions of previous estimates	(7,661)	(34,600)	(42,261)
Net change in income taxes	-	(21,206)	(21,206)
Net change in future development costs	3,539	(309)	3,230
Accretion of discount	(1,531)	3,124	1,593
Increase (decrease)	11,242	51,736	62,978
Standardized measure, beginning of year	10,243	8,046	18,289
Standardized measure, end of year	$ 21,485	$ 59,782	$ 81,267

Costs incurred in oil and gas property acquisition, exploration, and development activities were as follows:

	As at December 31,		
	2004	2003	2002
Property acquisition			
Proved	$ 3,204	$ -	$ -
Unproved	1,572	650	913
Exploration	11,276	3,148	10,841
Development	28,364	11,181	5,178
	$ 44,416	$ 14,979	$ 16,932

Development cost additions for the years ended December 31, 2004 and 2003 included $0.2 million and $0.4 million of asset retirement costs, respectively.

Depletion, per unit of net production, before provision for impairment were as follows:

U.S.
Year ended December 31, 2004 .... $16.80
Year ended December 31, 2003 .... $10.58
Year ended December 31, 2002 .... $ 8.39

China
Year ended December 31, 2004 .... $ 12.18
Year ended December 31, 2003 .... $ 10.23
Year ended December 31, 2002 .... $ 8.30

The results of operations from producing activities were as follows:

	2004			2003			2002		
	U.S.	China	Total	U.S.	China	Total	U.S.	China	Total
Oil and gas revenue	$ 9,311	$ 8,484	$ 17,795	$ 5,466	$ 4,103	$ 9,569	$ 5,099	$ 3,230	$ 8,329
Operating costs	3,159	1,914	5,073	2,313	1,980	4,293	2,351	1,490	3,841
Depletion (including provision for impairment)	19,428	2,630	22,058	22,253	1,477	23,730	1,906	1,202	3,108
Results of operations from producing activities	$ (13,276)	$ 3,940	$ (9,336)	$ (19,100)	$ 646	$ (18,454)	$ 842	$ 538	$ 1,380

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

We carried out an evaluation, under the supervision of and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our internal control over financial reporting pursuant to the requirements of the Securities Exchange Act of 1934. Based upon that evaluation, our management, including the Chief Executive Officer and Chief Financial Officer, concluded that, as at December 31, 2004, because of the issues referenced below, our internal control over financial reporting was not effective at a reasonable assurance level. Our management, including our Chief

Executive Officer and Chief Financial Officer believe, however, that when fully implemented, remediation measures will address the internal control deficiencies described below and will allow us to conclude that our internal control over financial reporting is effective at a reasonable level of assurance at future filing dates.

There were several significant changes in our internal control over financial reporting both during the year ended December 31, 2004 and since that date. These changes were in direct response to management's formal assessment of the effectiveness of the design and operation of our internal control over financial reporting. The Securities Exchange Act of 1934 requires an annual management report on the effectiveness of our internal control over financial reporting. Our independent registered chartered accountants must attest to this report. Although we would ordinarily include such information in our Annual Report on Form 10-K, we meet the eligibility requirements for a 45-day extension for the provision of this report and attestation, as detailed in an exemptive order by the U.S. Securities and Exchange Commission in November 2004. Because we have elected to use this extension, this Annual Report on Form 10-K does not include either the management report or the independent registered chartered accountants' attestation. These will instead be included in an amended Annual Report on Form 10-K that we expect to file in April 2005.

Our review to date of our internal control over financial reporting has brought to our attention two material weaknesses that are discussed below.

1. Information and Communication

Information systems produce reports, containing operational, financial and compliance-related information, that make it possible to run and control the business. Pertinent information must be identified, captured, and communicated in an effective manner to enable employees to carry out their responsibilities. These information systems deal not only with internally generated data, but also with the information about external events necessary to informed business decision-making and external reporting, such as industry, economic, and regulatory information. Effective communication also must occur in a broader sense, flowing down, across, and up the organization.

Our review of our information and communication procedures identified certain deficiencies. Taken together, the following deficiencies are considered to constitute a material weakness in internal control over financial reporting.

- a weakness in the procedure for the receipt of complaints regarding accounting, internal accounting controls, or auditing matters.
  - Section 301 of the Sarbanes-Oxley Act of 2002 requires our Audit Committee to establish procedures for "the confidential, anonymous submission by employees . . . regarding questionable accounting or auditing matters." Our current complaint procedure, applicable to both employees and third parties, directs complaints to our Corporate Secretary, who then advises the appropriate board committee or management member. We do not believe this procedure provides the requisite anonymity to a reporting employee or third party. As a result, we have adopted corrective measures that will be in place by March 31, 2005. An independent firm will handle all complaints, whether from employees or third parties. In addition, anyone wishing to raise concerns regarding accounting or auditing matters will be able to do so by means of a secure website.

- a lack of a formal process to ensure active ongoing communication of employees' roles and responsibilities related to internal control over financial reporting across the organization.
  - Although the importance of the safeguarding of our assets and the honest and accurate recording of information are key parts of our Code of Business Conduct, we do not formally review these processes with our employees on a regular basis. We will be formally communicating the roles and responsibilities related to internal control over financial reporting to all employees as part of our new complaint process noted above.

- a lack of a formal self-assessment process to monitor and detect control deficiencies related to internal control over financial reporting.
  - As part of our responsibilities under Section 404 of the Sarbanes-Oxley Act of 2002, there will be an annual and extensive formal review to monitor and detect control deficiencies related to internal control over financial reporting.

- our present fraud or misconduct response plans and policies are informal and do not provide a written and clear process for employees and external third parties to follow if they wish to report an issue, including inappropriate management overrides.
  - We will be formally communicating such plans and policies as part of our new complaint process noted above.

2. Financial Reporting Process

Our review of our financial reporting process identified several deficiencies, principally related to the lack of formal processes, division of duties and procedures for documentation of various approvals and reviews. Taken together, these deficiencies are

considered to constitute a material weakness in internal control over financial reporting. Management believes that these procedures and reviews were properly carried out and that the deficiencies identified during the review process relate principally to the lack of written evidence that procedures and reviews were properly completed. Prior to December 31, 2004 and since that date, we have changed many of our policies and procedures for the documentation of these reviews and procedures and have designed appropriate document retention policies to provide written evidence of our reviews and procedures.

As noted above, upon completion of our assessment of our internal control over financial reporting we currently expect to conclude that the above described two material weaknesses in our internal control over financial reporting existed as at December 31, 2004. However, we have not yet completed our assessment and so there may be other material weaknesses identified.

Accordingly, management expects to conclude that our internal control over financial reporting as at December 31, 2004 is ineffective, and Deloitte & Touche LLP has advised us that they expect their report on management's assessment of internal control over financial reporting will also indicate that internal control over financial reporting was ineffective as at December 31, 2004.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The following table provides the names of all of our directors and executive officers, their positions, terms of office and their principal occupations during the past five years. Each director is elected for a one-year term or until his successor has been duly elected or appointed. Officers serve at the pleasure of the Board of Directors.

Name, Age and Municipality of Residence	Position with the Registrant	Present Occupation and Principal Occupation for the Past Five Years
DAVID R. MARTIN, age 73 .... Santa Barbara, California	Chairman of the Board and Director (since August, 1998)	Chairman of the Board of Ivanhoe Energy Inc. (August 1998 — present); President, Cathedral Mountain Corporation (1997 — present); President and Chief Executive Officer, Occidental Oil and Gas Corporation (1986-1996); Executive Vice President and Director, Occidental Petroleum Corporation (1986-1996)
ROBERT M. FRIEDLAND, age 54 .... Hong Kong	Deputy Chairman (since June, 1999) and Director (since February, 1995)	Chairman and President, Ivanhoe Capital Corporation, a Singapore based venture capital company principally involved in establishing and financing international mining and exploration companies; Chairman and Director, Ivanhoe Mines Ltd. (March 1994 — present)
E. LEON DANIEL, age 68 .... Park City, Utah	President, Chief Executive Officer (since June, 1999) and Director (since August, 1998)	President and Chief Executive Officer of Ivanhoe Energy Inc. (June, 1999 — present); Executive Vice President, Worldwide Business Development, Occidental Oil and Gas Corporation (1996-1998); Vice President Engineering, Drilling and Production, Occidental Petroleum Corporation (1997-1998)
JOHN A. CARVER, age 72 .... Bakersfield, California	Director (since August, 1998)	Retired (1998); Senior Vice President, Worldwide Exploration, Occidental Petroleum Corporation (1997-1998)
R. EDWARD FLOOD, age 59............ Reno, Nevada	Director (since June, 1999)	Deputy Chairman and Director, Ivanhoe Mines Ltd. (May 1999 — present); Mining Analyst, Haywood Securities (May, 1999 — September 2001); President, Ivanhoe Mines Ltd. (1995-1999)
SHUN-ICHI SHIMIZU, age 64 .... Tokyo, Japan	Director (since July, 1999)	Managing Director of C.U.E. Management Consulting Ltd. (1994 — present)
HOWARD R. BALLOCH, age 53....... Beijing, China	Director (since January, 2002)	President, The Balloch Group (July 2001 — present); President, Canada China Business Council (July 2001 — present); Canadian Ambassador to China, Mongolia and Democratic Republic of Korea (April 1996 — July 2001); Director, Methanex Corporation (December 2004 — present); Director. Zi Corporation (August 2001 — present); Director Magic Lantern Corporation (December 2003— present)
J. STEVEN RHODES, age 53 .... Los Angeles, California	Director (since December, 2003)	Chairman and Chief Executive Officer. Claiborne-Rhodes, Inc. (2001 — present); Senior Vice President, First Southwest Company (1999— 2001); White House, Chief Domestic Advisor to Vice President George Bush (1981 — 1985)
W. GORDON LANCASTER, C.A. age 61.. Vancouver, British Columbia	Chief Financial Officer (Since January, 2004)	Vice President Finance and Chief Financial Officer of Xantrex Technology Inc., (July 2003 — December 2003); Vice President Finance and Chief Financial Officer of Power Measurement, Inc., (August 2000 — June 2003); Senior President Finance and Chief Financial Officer of Lions Gate Entertainment Corp., (1998 —2000)
PATRICK CHUA, age 49.................... Hong Kong, China	Executive Vice-President (since June, 1999)	Executive Vice-President of Ivanhoe Energy Inc. (June, 1999 — present); President and Director of Sunwing Energy Ltd. (Bermuda) (March 2000 — present): Co-Chairman and Director of Sunwing Energy Ltd. (June, 1996 — June, 1999)
GERALD MOENCH, age 56.............. Lethbridge, Alberta	Executive Vice-President (since June, 1999)	Executive Vice-President of Ivanhoe Energy Inc. (June, 1999 — present); President and Director, Sunwing Energy Ltd. (July, 1997 — June, 1999)

Each of our directors was elected at our last annual general meeting of shareholders held on April 29, 2004. The term of office of each director concludes at our next annual general meeting of shareholders, unless the director's office is earlier vacated in accordance with our by-laws. There are no family relationships among any of our directors, officers or key employees.

As required under the *Business Corporations Act* (Yukon), our Board of Directors has an Audit Committee. We also have a Compensation Committee. The members of the Audit Committee are Messrs. Edward Flood, Howard Balloch and Steven Rhodes. Mr. Rhodes replaced Mr. Shun-ichi Shimizu effective March 2, 2004. Mr. Flood, one of our independent directors, has been determined by the Board of Directors to be an Audit Committee financial expert. We believe that Mr. Flood's prior experience as the chief executive officer of a public traded mining company, as a member of the management of a U.S. investment fund and as a mining analyst for a Canadian brokerage firm provides a sufficient basis for considering him to be an Audit Committee financial expert. The members of the Compensation Committee are Messrs. Edward Flood, Howard Balloch and Steven Rhodes. Mr. Rhodes was appointed to the Compensation Committee on March 2, 2004.

Management is responsible for our financial reporting process including our system of internal controls over financial reporting and for the preparation of consolidated financial statements in accordance with generally accepted accounting principles in Canada. Our independent registered chartered accountants are responsible for auditing those financial statements. The members of the Audit Committee are not our employees, and are not professional accountants or auditors. The Audit Committee's primary purpose is to assist the Board of Directors in fulfilling its oversight responsibilities by reviewing the financial information provided to shareholders and others, and the systems of internal controls which management has established to preserve our assets and the audit process. It is not the Audit Committee's duty or responsibility to conduct auditing or accounting reviews or procedures or to determine that our financial statements are complete and accurate and in accordance with generally accepted accounting principles in Canada. In giving its recommendation to the Board of Directors, the Audit Committee has relied on management's representations that the financial statements have been prepared with integrity and objectivity and in conformity with generally accepted accounting principles in Canada and on the opinion of the independent registered chartered accountants included in their report on our financial statements.

Based solely on a review of the reports furnished to us, we believe that during 2004 all of our directors, executive officers and 10% shareholders complied with the applicable Canadian requirements for reporting initial ownership and changes in ownership of our common shares.

Code of Business Conduct and Ethics

We have a Code of Business Conduct and Ethics applicable to all employees, consultants, officers and directors regardless of their position in our organization, at all times and everywhere we do business. The Code of Business Conduct and Ethics provides that our employees, consultants, officers and directors will uphold our commitment to a culture of honesty, integrity and accountability and that we require the highest standards of professional and ethical conduct from our employees, consultants, officers and directors. Our Code of Business Conduct and Ethics has been filed as Exhibit 14.1 to our 2004 Annual Report on Form 10-K. A copy of our Code of Business Conduct and Ethics may be obtained, without charge, by request to Ivanhoe Energy Inc., 654-999 Canada Place, Vancouver, British Colombia, Canada V6C 3E1, Attention: Investor Relations or by phone to 604-688-8323.

ITEM 11. EXECUTIVE COMPENSATION

In accordance with the requirements of applicable securities legislation in Canada, the following executive compensation disclosure is provided in respect of the our Chief Executive Officer and Chief Financial Officer as at December 31, 2004, and each of our three most highly compensated executive officers whose annual compensation exceeded Cdn.$150,000 in the year ended December 31, 2004 (collectively, the "**Named Executive Officers**"). During the year ended December 31, 2004, the aggregate compensation paid to all of our executive officers whose annual compensation exceeded Cdn.$40,000 was U.S.$1,285,834.

Summary Compensation Table

The following table sets forth a summary of all compensation paid during the years ending December 31, 2004, 2003 and 2002 to each of the Named Executive Officers.

SUMMARY COMPENSATION TABLE ($U.S.)

Name and Principal Position	Year	Annual Compensation			Long Term Compensation			All Other Compen-sation [7]
					Awards		Payouts	
		Salary	Bonus[6]	Other Annual Compen-sation	Securities Under Options/ SARs Granted (#)	Restricted Shares or Restricted Share Units	LTIP Payouts	
E. Leon Daniel President & Chief Executive Officer[1]	2004 2003 2002	300,000 332,610 266,500	90,000 81,123 -	- - -	- - -	- - -	- - -	12,792 9,792 5,415
David R. Martin Chairman[2]	2004 2003 2002	200,000 205,562 253,167	60,000 54,082 -	- -	- - -	- - -	- - -	12,792 9,792 7,200
Patrick Chua Executive Vice President[3]	2004 2003 2002	144,000 144,000 182,970	- 32,449 -	- - -	- - 60,000	- - -	- - -	- - -
Gerald Moench Executive Vice President[4]	2004 2003 2002	165,000 150,000 152,475	41,250 33,801 -	- - -	- - 50,000	- - -	- - -	- - -
W. Gordon Lancaster Chief Financial Officer [5]	2004	200,000	60,000	-	250,000	-	-	-

(1) Mr. Daniel was appointed President and Chief Executive Officer in June 1999, and has been one of our directors since August 1998.
(2) Mr. Martin has been Chairman and one of our directors since August 1998.
(3) Mr. Chua was appointed as an Executive Vice President in June 1999.
(4) Mr. Moench was appointed an Executive Vice President in June 1999.
(5) Mr. Lancaster was appointed Chief Financial Officer effective January 2004.
(6) Bonuses earned are payable in cash and common shares from our Employees' and Directors' Equity Incentive Plan at fair market value on the date of approval by the Compensation Committee.
(7) Our matching contribution to the 401(k) plan, a U.S. defined contribution retirement plan available to U.S. employees.

Long Term Incentive Plan

We do not presently have a long-term incentive plan for any of our executive officers, including our Named Executive Officers.

Options and Stock Appreciation Rights (SARs)

During the year ended December 31, 2004, Mr. Lancaster received an incentive stock option to acquire 250,000 common shares, which vest over 4 years and expire on the 5th anniversary of the date of grant. Although this option was granted during the fourth quarter of 2003 in anticipation of Mr. Lancaster's appointment as Chief Financial Officer, it did not become exercisable by Mr. Lancaster until January 1, 2004, the date upon which his appointment as Chief Financial Officer took effect. No other stock options or SARs were granted to our Named Executive Officers in the year ended December 31, 2004.

NEO Name (a)	Securities, Under Options/SARs Granted (#) (b)	Percent of Total Options/ SARs Granted to Employees in Financial Year (c)	Exercise or Base Price ($/Security) (d)	Market Value of Securities Underlying Options/ SARs on the Date of Grant ($/Security) (e)	Expiration Date (f)
W. Gordon Lancaster, CFO	250,000	35.29%	Cdn. $5.68	Cdn. $1,420,000	December 31, 2009

Aggregated Option Exercises

During the year ended December 31, 2004, Mr.. Chua exercised 500,000 options at Cdn. $2.50 per common share and Mr. Moench exercised options for 45,000 common shares at Cdn. $2.50 per common share. No other Named Executive Officers exercised options in 2004.

Name	Shares Acquired on Exercise (#)	Value Realized ($U.S.)	Number of Securities Underlying Unexercised Options at December 31, 2004 (#) Exercisable/Unexercisable	Value of Unexercised In-the-Money Options at December 31, 2004 ($U.S.) Exercisable/Unexercisable
E. Leon Daniel	—	—	666,667 / 0	351,782 / 0
David R. Martin	—	—	3,400,000 / 0	7,176,334 / 0
Patrick Chua	500,000	417,355	36,000 / 24,000	—
Gerald Moench	45,000	10,650	30,000 / 20,000	—
W. Gordon Lancaster	—	—	100,000 / 150,000	—

Option and SAR Repricings

No options or stock appreciation rights were re-priced during the year ended December 31, 2004.

Defined Benefit and Actuarial Plan

We do not presently provide a pension plan for our employees. However, in 2001 we adopted a defined contribution retirement or thrift plan ("**401(k) Plan**") to assist U.S. employees in providing for retirement or other future financial needs. Employees' contributions (up to the maximum allowed by U.S. tax laws) are matched by us 50% starting in 2001 and increasing 10% per year thereafter to a maximum of 100%. Our matching contributions to the 401(k) Plan were $0.2 million per year for 2004 and 2003 and $0.1 million for 2002.

Employment Contracts, Termination of Employment and Change-In-Control Arrangements

We have written contracts of employment with Messrs. E. Leon Daniel and W. Gordon Lancaster. Otherwise, we have no written employment contracts or termination of employment or change of control arrangements with any of our directors or Named Executive Officers. Each of the written employment contracts we have with the Named Executive Officers allows us to terminate the Named Executive Officer for cause in which case the Named Executive Officer would have no entitlement to any compensation with respect to the termination. None of the contracts provides for a change of control arrangement.

Mr. Daniel's contract provides for an annual salary of not less than $300,000 over the term of employment of five years, commencing on April 30, 2002, unless terminated earlier in accordance with the provisions of the contract. Either party may terminate the contract upon one year's notice provided however that we may terminate Mr. Daniel's employment at any time without notice by paying him an amount equal to the lesser of one year's salary or the prorated amount of his annual salary that he would have earned between the date of termination and the expiration of the contract term. Mr. Daniel is eligible to receive a cash bonus and a stock bonus each year, as determined by the Compensation Committee. Mr. Daniel is entitled to participate in our employee benefit programs on the same basis as all of our other employees.

As of January 1, 2004, we entered into an employment contract with Mr. Lancaster having no fixed term of employment and providing for an initial annual salary of $200,000, subject to review annually by the Compensation Committee, and the same benefit entitlements available to our other executive officers. Under the terms of the contract, Mr. Lancaster was granted an initial incentive stock option to acquire 250,000 common shares, which vest over 4 years and expire on the 5th anniversary of the date of grant. We may terminate Mr. Lancaster's employment for any reason by delivering to him six months' written notice.

Director Compensation

All independent directors receive director fees of $2,000 per month. We did not pay any other cash or fixed compensation to our directors for acting as such. We reimburse our directors for expenses they reasonably incur in the performance of their duties as directors and they are also eligible to participate in our Employees' and Directors' Equity Incentive Plan. One of our non-executive directors, Mr. John A. Carver, was engaged as a full time employee effective January 1, 2002 and receives a salary in his capacity as an employee.

Employees' and Directors' Equity Incentive Plan

Our Employees' and Directors' Equity Incentive Plan, as amended (the "**Plan**") consists of three component plans: a common share option plan (the "**Share Option Plan**"), a common share bonus plan (the "**Share Bonus Plan**"), and a common share purchase plan (the "**Share Purchase Plan**"). The purpose of the Plan is to advance our corporate interests by encouraging equity participation by our directors, officers, employees and service providers through the acquisition of our shares.

The following is a brief description of the terms of the Plan.

Share Option Plan

The Share Option Plan allows the Board of Directors to grant options to acquire our common shares in favor of our directors, officers, employees and service providers. Options are subject to adjustment in the event of a subdivision or consolidation of our common shares, an amalgamation, or other corporate event affecting our common shares. Participation in the Share Option Plan is limited to directors, officers, employees and service providers who are, in the opinion of our Board of Directors, in a position to contribute to our future growth and success.

In determining the number of common shares made subject to an option, we consider, among other things, the optionee's relative present and potential contribution to our success and to the prevailing policies of each stock exchange on which our shares are listed. The Board of Directors determines the date of grant, the number of optioned common shares, the exercise price per share, the vesting period and the exercise period. The minimum exercise price of any option granted under the Share Option Plan is the weighted average price of our common shares on the principal stock exchange on which our common shares trade for the five trading days prior to the date of grant.

Unless earlier terminated upon an optionee's death or termination of employment or appointment, options are exercisable for a period of up to ten years. We may, in our discretion, accelerate unvested options if a take-over bid is made for our common shares.

Share Bonus Plan

The Share Bonus Plan permits our Board of Directors to issue up to an aggregate maximum of 2,000,000 of our common shares as bonus awards to our directors, officers, employees and service providers on a discretionary basis having regard to such merit criteria as the Board of Directors may determine. As at December 31, 2004, there were 1,045,712 shares available to be issued from the Share Bonus Plan.

Share Purchase Plan

Participation in the Share Purchase Plan is limited to employees who have completed at least one year (or less, at the discretion of the Board of Directors) of continuous service on a full-time basis and who are designated by the Board of Directors as eligible to participate in the Share Purchase Plan.

Eligible employees may contribute up to 10% of their annual basic salary to the Share Purchase Plan in semi-monthly installments. We then make contributions on a quarterly basis equal to the employee's contribution.

At the end of each calendar quarter, the eligible employee receives a number of our common shares equal to the aggregate amount contributed by the employee participant and by us, on the participant's behalf, divided by the weighted average trading price of our common shares on our principal stock exchange during the previous three months.

The Share Purchase Plan component of the Plan has not yet been activated.

General

The aggregate maximum number of our common shares, which we may issue, or reserve for issuance under the Plan, is currently 20,000,000 common shares. Any increase is subject to Toronto Stock Exchange approval and approval by our shareholders. The maximum number of our common shares which we may, at any time, reserve for issuance to any one person under the Plan may not exceed 5% of our issued and outstanding common shares. As at December 31, 2004, there were 5,139,386 unallocated shares available to be issued from our Plan.

Our Board of Directors has the right to amend, modify or terminate our Plan. However, any amendment to the Plan which would materially increase the benefits under the Plan, materially modify the requirements as to eligibility for participation in the Plan or materially change the number of our common shares that may be issued or reserved for issuance under the Plan, is subject to Toronto Stock Exchange approval and the approval of our shareholders.

Compensation Committee Interlocks and Insider Participation

During the year ended December 31, 2004, our Compensation Committee consisted of Messrs. R. Edward Flood, Howard R. Balloch and J. Steven Rhodes. Mr. Rhodes was appointed to the Compensation Committee on April 29, 2004.

Board Compensation Committee Report on Executive Compensation

Our executive compensation program is administered by the Compensation Committee. The members of the Compensation Committee are all outside, unrelated directors. Following review and approval by the Compensation Committee, decisions relating to executive compensation are reported to, and approved by, the full Board of Directors. The Compensation Committee has directed the preparation of this report and has approved its contents and its submission to shareholders.

Our approach to executive compensation program is motivated by a desire to align the interests of our executive officers as closely as possible with the interests of Ivanhoe and its shareholders as a whole. In determining the nature and quantum of compensation for our executive officers we are seeking to achieve the following objectives: to provide a strong incentive to management to contribute to the achievement of our short-term and long-term corporate goals; to ensure that the interests of our executive officers and the interests of our shareholders are aligned; to enable us to attract, retain and motivate executive officers of the highest caliber in light of the strong competition in our industry for qualified personnel; and to recognize that the successful implementation of Ivanhoe's corporate strategy cannot necessarily be measured, at this stage of its development, with reference to quantitative measurement criteria of corporate or individual performance. We take all of these factors into account in formulating our recommendations to the Board of Directors respecting the compensation to be paid to each of our executive officers.

The compensation that we pay to our executive officers generally consists of cash, equity and equity incentives. Our compensation policy reflects a belief that an element of total compensation for our executive officers should be "at risk" in the form of common shares or incentive stock options, so as to create a strong incentive to build shareholder value. The Compensation Committee oversees and sets the general guidelines and principles for the compensation packages for senior management. As well, the Compensation Committee assesses the individual performance of our executive officers and makes recommendations to the Board of Directors. Based on these recommendations, the Board of Directors makes decisions concerning the nature and scope of the compensation to be paid to our executive officers. The Compensation Committee is also responsible for considering grants of equity and equity incentives to non-executive management personnel under Ivanhoe's Plan.

The base salaries of our executive officers are determined using a subjective assessment of each individual's performance, experience and other factors we believe to be relevant, including prevailing industry demand for personnel having comparable skills and performing similar duties, the compensation the individual could reasonably expect to receive from a competitor and Ivanhoe's ability to pay. We also consider recommendations from outside compensation consultants and use compensation data obtained from publicly available sources. We believe that the salaries we currently pay to our executive officers reasonably approximate the median level of most of the comparative compensation data to which we had access. All of our executive officers are eligible to receive discretionary bonuses, based upon our subjective assessment of Ivanhoe's overall performance in relation to its ongoing implementation of corporate strategy and achievement of corporate objectives and of each executive officer's contribution to such performance and achievement. Incentive bonuses awarded for the 2004 fiscal year consisted of 50% cash and 50% common shares issued at fair market value under the Share Bonus Plan.

The specific relationship of corporate performance to executive compensation under our executive compensation program is created through equity compensation mechanisms. Incentive stock options, which vest and become exercisable through the passage of time, link the bulk of our equity-based executive compensation to shareholder return, measured by increases in the market price of our common shares. We also make, as and when we consider it warranted, recommendations to the Board of Directors respecting discretionary bonus awards of common shares to our employees, including our executive officers. Such awards are intended to recognize extraordinary contributions to the achievement of corporate objectives.

Eligibility for participation from time to time in the various equity incentive mechanisms available under our Plan is determined after we have thoroughly reviewed and taken into consideration the individual performance and contribution to overall corporate performance by each prospective participant. All outstanding stock options that have been granted under our Plan were granted at prices not less than 100% of the fair market value of Ivanhoe common shares on the dates such options were granted.

Although Ivanhoe has, in the past, relied heavily upon incentive stock options to compensate its executive officers, we do not have a policy of granting additional incentive stock options to our executive officers on an annual basis. We continue to believe, however, that stock-based incentives encourage and reward effective management that results in long-term corporate financial success, as measured by stock appreciation. Stock-based incentives awarded to our executive officers are based on the Committee's subjective evaluation of each executive officer's ability to influence our long-term growth and to reward outstanding individual performance and contributions to our business. Other factors influencing our recommendations respecting the nature and scope of the equity compensation and equity incentives to be awarded to our executive officers in a given year include: awards made in previous years and, particularly in the case of equity incentives, the number of incentive stock options that remain outstanding and exercisable from grants in previous years and the exercise price and the remaining exercise term of those outstanding stock options.

With effect as of January 1, 2004, Ivanhoe granted to Mr. Lancaster, the Corporation's Chief Financial Officer, incentive stock options exercisable to purchase up to 250,000 common shares at a price of Cdn.$5.68 per share. Otherwise, Ivanhoe did not grant any incentive stock options to its executive officers during 2004.

The compensation paid to our Chief Executive Officer for the fiscal year ended December 31, 2004 was based on the same basic factors and criteria used to determine executive compensation generally. We believe that there is necessarily some subjectivity involved in determining the compensation of our Chief Executive Officer and we do not use quantitative performance criteria when setting his compensation. In determining an appropriate level of compensation for our Chief Executive Officer, we subjectively and qualitatively analyze Ivanhoe's overall performance in relation to its ongoing implementation of corporate strategy and achievement of corporate objectives and of our Chief Executive Officer's contribution to such performance and achievement. Specific factors considered in setting bonus levels include shareholder returns, our operational and financial results and the success of our acquisition, exploration and development programs and strategies. We also consider our Chief Executive Officer's level and scope of responsibility, experience and the compensation practices of other industry participants for executives of similar responsibility.

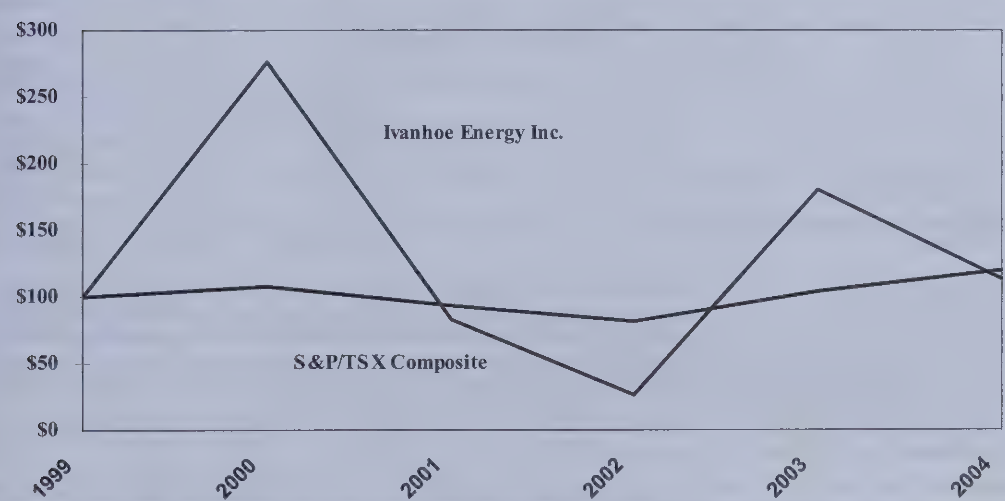
Our Chief Executive Officer's minimum salary is set by his employment contract, the material terms of which are described under "Employment Contracts, Termination of Employment and Change-in-Control Arrangements". This contract also provides that our Chief Executive Officer is eligible to receive, on an annual basis, a cash bonus and a non-cash bonus in an amount determined by the Compensation Committee based on such criteria as the Committee may determine from time to time. We awarded a bonus of $90,000 to our Chief Executive Officer in respect of the 2004 fiscal year. This bonus consisted of 50% cash and 50% common shares issued at fair market value under the Share Bonus Plan. In determining the quantum of our Chief Executive Officer's bonus, the principal factor we took into account were his efforts in generating new project opportunities in Iraq and Colombia and in negotiating the terms of our proposed acquisition of Ensyn.

Submitted on behalf of the Compensation Committee:

Mr. Howard R. Balloch
Mr. R. Edward Flood
Mr. J. Steven Rhodes

Performance Graph

The following graph and table compares the cumulative shareholder return on a $100 investment in our common shares to a similar investment in companies comprising the S&P/TSX Composite Index, including dividend reinvestment, for the period from December 31, 1999 to December 31, 2004.



	As at December 31, (Cdn.$)					
	1999	2000	2001	2002	2003	2004
Ivanhoe Energy Inc.	$100	$276	$83	$27	$180	$113
S&P/TSX Composite Index	$100	$107	$94	$82	$104	$119

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Except as set forth below, no person or group is known to beneficially own 5% or more of our issued and outstanding common shares. Based on information known to us, the following table sets forth the beneficial ownership of each such person or group in our common shares as at February 2, 2005.

Title of Class	Name and Address of Beneficial Owner	Number of Shares Beneficially Owned (1)	Percentage of Class
Common Shares	Robert M. Friedland Flat B, 31st Floor Primrose Court 56A Conduit Road Hong Kong	46,611,725 (2)	27.44
Common Shares	Directors and Executive Officers as a Group (11 persons)	53,858,498 (3)	30.77

(1) Beneficial ownership is determined in accordance with the rules of the SEC and generally includes voting or investment power with respect to securities. Unissued common shares subject to options, warrants or other convertible securities currently exercisable or convertible, or exercisable or convertible within 60 days, are deemed outstanding for the purpose of computing the beneficial ownership of common shares of the person holding such convertible security but are not deemed outstanding for computing the beneficial ownership of common shares of any other person.
(2) 46,611,725 common shares are held indirectly through Newstar Securities SRL, Premier Mines Ltd. and Evershine LLC, companies controlled by Mr. Friedland.
(3) Includes 5,176,667 unissued common shares issuable to directors and senior officers upon exercise of incentive stock options.

Security Ownership of Management

The following table sets forth the beneficial ownership as at February 2, 2005 of our common shares by each of our directors, our Named Executive Officers and by all of our directors and executive officers as a group:

Title of Class	Name of Beneficial Owner	Amount and Nature of Beneficial Ownership (1) (a)	Percentage of Class (b)	Incentive Stock Options Included in (a) (c)
Common Shares	David R. Martin	4,351,672	2.51	3,400,000
Common Shares	Robert M. Friedland	46,611,725 (2)	27.44	-
Common Shares	E. Leon Daniel	1,286,163	0.75	666,667
Common Shares	John A. Carver	563,302	0.33	250,000
Common Shares	R. Edward Flood	75,029	0.04	50,000
Common Shares	Shun-ichi Shimizu	98,500	0.06	-
Common Shares	J. Steven Rhodes	300,000	0.18	300,000
Common Shares	W. Gordon Lancaster	273,100	0.16	250,000
Common Shares	Patrick Chua	75,300	0.04	60,000
Common Shares	Gerald Moench	73,707	0.04	50,000
Common Shares	Howard R. Balloch	150,000	0.09	150,000
Common Shares	All directors and executive officers as a group (11 persons)	53,858,498 (3)	30.77	5,176,667

(1) Beneficial ownership is determined in accordance with the rules of the SEC and generally includes voting or investment power with respect to securities. Unissued common shares subject to options, warrants or other convertible securities currently exercisable or convertible, or exercisable or convertible within 60 days, are deemed outstanding for the purpose of computing the beneficial ownership of common shares of the person holding such convertible security but are not deemed outstanding for computing the beneficial ownership of common shares of any other person.
(2) 46,611,725 common shares are held indirectly through Newstar Securities SRL, Premier Mines Ltd. and Evershine LLC, companies controlled by Mr. Friedland.
(3) Includes 5,176,667 unissued common shares issuable to directors and senior officers upon exercise of incentive stock options.

Securities Authorized for Issuance under Equity Compensation Plans

Our shareholders have approved our Plan and all amendments increasing the number of common shares available for issuance under the Plan. The Plan is intended to further align our directors' and management's interests with the Company's long-term performance and the long-term interests of our shareholders. The material terms of the Plan are summarized in Item 11 Executive Compensation. The following information is as at December 31, 2004:

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by Securityholders	8,245,760	$2.65	5,139,386
Equity compensation plans not approved by Securityholders	-	-	-
Total	8,245,760	$2.65	5,139,386

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Transactions with Management and Others

We borrowed $1.25 million from Ivanhoe Capital Finance Ltd., a company wholly owned by Mr. Robert M. Friedland. The unsecured loan was repaid with accrued interest, at U.S. prime plus 3%, in September 2003. We negotiated a revolving credit facility of $1.25 million to re-establish or extend that loan in the future as needs arise.

Certain Business Relationships

We are party to cost sharing agreements with other companies wholly or partially owned by Mr. Robert M. Friedland. Through these agreements, we share office space, furnishings, equipment and communications facilities in Vancouver, Beijing and Singapore. We also share the costs of employing administrative and non-executive management personnel at these offices. During the year ended December 31, 2004, our share of costs for the Vancouver and Singapore offices was $0.9 million and we were reimbursed $0.3 million by Mr. Friedland's companies for their share of costs for our Beijing office.

During the year ended December 31, 2004, a company controlled by Mr. Shun-ichi Shimizu received $0.7 million for consulting services and out of pocket expenses.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following table summarizes the aggregate fees billed by Deloitte & Touche LLP:

	Year ended December 31, Cdn.($000) 2004	2003
Audit Fees (a)	$ 314	$ 183
Audit Related Fees (b)	134	-
Tax Fees (c)	124	43
	$ 572	$ 226

(a) Fees for audit services billed in 2004 and 2003 consisted of:
- Audit of our annual financial statements
- Reviews of our quarterly financial statements
- Comfort letters, statutory and regulatory audits, consents and other services related to Canadian and U.S. securities regulatory matters
- Review of our internal controls over financial reporting in compliance with the requirements of the Sarbanes Oxley Act of 2002.

(b) Fees for audit related services billed in 2004 consist of financial and tax analysis in contemplation of our proposed merger with Ensyn Group, Inc.

(c) Fees for tax services billed in 2004 and 2003 consisted of tax compliance and tax planning and advice:
- Fees for tax compliance services totaled Cdn.$58,000 and Cdn.$36,000 in 2004 and 2003, respectively. Tax compliance services are services rendered based upon facts already in existence or transactions that have already occurred to document, compute, and obtain government approval for amounts to be included in tax filings and consisted of:
    i. Federal, state and local income tax return assistance
    ii. Preparation of expatriate tax returns
    iii. Assistance with tax return filings in certain foreign jurisdictions
- Fees for tax planning and advice services totaled Cdn.$66,000 and Cdn.$7,000 in 2004 and 2003, respectively. Tax planning and advice are services rendered with respect to proposed transactions or that alter a transaction to obtain a particular tax result. Such services consisted of:

i. Tax advice related to structuring certain proposed mergers, acquisitions and disposals.

In considering the nature of the services provided by Deloitte & Touche LLP, the Audit Committee determined that such services are compatible with the provision of independent audit services. The Audit Committee discussed these services with Deloitte & Touche LLP and our management to determine that they are permitted under the rules and regulations concerning auditor independence promulgated by the SEC to implement the Sarbanes-Oxley Act of 2002, as well as the American Institute of Certified Public Accountants.

Audit Committee Approval

Before Deloitte & Touche LLP is engaged by us or our subsidiaries to render audit or non-audit services, the engagement is approved by our Audit Committee.

The Audit Committee has adopted a pre-approval policy for audit or non-audit service engagements. This policy describes the permitted audit, audit-related, tax, and other services (collectively, the "**Disclosure Categories**") that Deloitte & Touche LLP may perform. The policy requires that, prior to the beginning of each fiscal year, a description of the services (the "**Service List**") expected to be performed by Deloitte & Touche LLP in each of the Disclosure Categories in the following fiscal year be presented to the Audit Committee for approval. Services provided by Deloitte & Touche LLP during the following year that are included in the Service List are pre-approved following the policies and procedures of the Audit Committee.

Any requests for audit, audit-related, tax, and other services not contemplated on the Service List must be submitted to the Audit Committee for specific pre-approval and cannot commence until such approval has been granted. Normally, pre-approval is provided at regularly scheduled meetings. However, the authority to grant a specific pre-approval between meetings, as necessary, has been delegated to the Chairman of the Audit Committee. The Chairman must update the Audit Committee at the next regularly scheduled meeting of any services that were granted specific pre-approval.

In addition, although not required by the rules and regulations of the SEC, the Audit Committee generally requests a range of fees associated with each proposed service on the Service List and any services that were not originally included on the Service List. Providing a range of fees for a service incorporates appropriate oversight and control of the independent auditor relationship, while permitting us to receive immediate assistance from the independent auditor when time is of the essence. On a quarterly basis, the Audit Committee reviews the status of services and fees incurred year-to-date against the original Service List and the forecast of remaining services and fees for the fiscal year.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

The following financial statements and exhibits are filed as part of this Annual Report on Form 10-K:

(a) 1. **Financial Statements:**

Deloitte & Touche LLP Report of Independent Registered Chartered Accountants on Consolidated Balance Sheets of Ivanhoe Energy Inc. as at December 31, 2004 and 2003 and Consolidated Statements of Loss and Shareholders' Equity and Cash Flow of Ivanhoe Energy Inc. for the years ended December 31, 2004, 2003 and 2002

Consolidated Balance Sheets of Ivanhoe Energy Inc. as at December 31, 2004 and 2003

Consolidated Statements of Loss of Ivanhoe Energy Inc. for the years ended December 31, 2004, 2003 and 2002

Consolidated Statements of Shareholders' Equity for the years ended December 31, 2004, 2003 and 2002

Consolidated Statements of Cash Flow of Ivanhoe Energy Inc. for the years ended December 31, 2004, 2003 and 2002.

2. **Financial Statement Schedules:**

Quarterly Financial Data in Accordance with Canadian and U.S. GAAP (Unaudited)

Supplementary Disclosures about Oil and Gas Production Activities (Unaudited)

3. **Exhibits**

3.1 Articles of Ivanhoe Energy Inc. as amended to June 24, 1999 (Incorporated by reference to Exhibits 1.1 through to 1.4 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000)

3.2 Bylaws of Ivanhoe Energy Inc. as amended May 15, 2001

10.1	Petroleum Contract for Kongnan Block, Dagang Oilfield of the People's Republic of China dated September 8, 1997 between China National Petroleum Corporation and Pan-China Resources Ltd., as amended June 11, 1999 (Incorporated by reference to Exhibit 3.15 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000)
10.2	Volume License Agreement dated April 26, 2000 between Syntroleum Corporation and Ivanhoe Energy Inc. (Incorporated by reference to Exhibit 3.37 of Amendment No. 2 to Form 20-F filed with the Securities and Exchange Commission on July 24, 2000)
10.3	Master License Agreement Amendment No. 1 dated October 11, 2000 between Syntroleum Corporation and Ivanhoe Energy Inc. (Incorporated by reference to Exhibit 10.18 of Form 10-K filed with the Securities and Exchange Commission on March 16, 2001)
10.4	Joint Study Agreement between PetroChina Company Limited and Sunwing Energy Ltd. dated March 29, 2001, for the purposes of entering into Production Sharing Contracts on the Yudong block. (Incorporated by reference to Exhibit 10.21 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)
10.5	Joint Venture Agreement and Operating Agreement dated July 1, 2001 between Union Oil Company of California and Ivanhoe Energy (USA) Inc. on the Creslenn Ranch Area, Henderson County, Texas. (Incorporated by reference to Exhibit 10.23 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)
10.6	Joint Venture Agreement and Operating Agreement dated October 1, 2001 between Union Oil Company of California and Ivanhoe Energy (USA) Inc., in the Bossier Trend, Anderson, Freestone & Henderson Counties, Texas (Incorporated by reference to Exhibit 10.24 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)
10.7	Consulting Agreement dated January 13, 2002 between Ivanhoe Energy Inc. and Nahwan Trading LLC. (Incorporated by reference to Exhibit 10.27 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)
10.8	Petroleum Contract dated September 19, 2002 between China National Petroleum Corporation and Pan-China Resources Ltd. for Zitong Block, Sichuan Basin of the People's Republic of China. (Incorporated by reference to Exhibit 10.12 of Form 10-K filed with the Securities and Exchange Commission on March 19, 2003)
10.9	Strategic Development Alliance Letter Agreement dated September 26, 2002 between Ivanhoe Energy Inc. and CITIC Energy Ltd. (Incorporated by reference to Exhibit 10.13 of Form 10-K filed with the Securities and Exchange Commission on March 19, 2003)
10.10	Cooperation Agreement between Ensyn Petroleum International Ltd. and Ivanhoe Energy (USA) Inc. dated May 30, 2003 (Incorporated by reference to Exhibit 10.14 of Form 10-K filed with the Securities and Exchange Commission on March 15, 2004)
10.11	Employees' and Directors' Equity Incentive Plan (Incorporated by reference to Exhibit 10.15 of Form 10-K filed with the Securities and Exchange Commission on March 15, 2004)
10.12	Agreement in Principle for GTL Project Development between Syntroleum Corporation and the Company dated June 18, 2003 (Incorporated by reference to Exhibit 10.16 of Form 10-K filed with the Securities and Exchange Commission on March 15, 2004)
10.13	Amendment No. 3 to Master License Agreement between Syntroleum Corporation and the Company dated July 1, 2003 (Incorporated by reference to Exhibit 10.17 of Form 10-K filed with the Securities and Exchange Commission on March 15, 2004)
10.14	Heads of Agreement between China International Trust and Investment Corporation and the Company dated November 18, 2003 (Incorporated by reference to Exhibit 10.19 of Form 10-K filed with

	the Securities and Exchange Commission on March 15, 2004)
10.15	Stock Purchase and Shareholders Agreement by and among Ensyn Group, Inc., Ensyn Petroleum International Ltd. and Ivanhoe Energy (USA) Inc. dated January 15, 2004 (Incorporated by reference to Exhibit 10.20 of Form 10-K filed with the Securities and Exchange Commission on March 15, 2004)
10.16	LAK Ranch Farm-in Agreement between Derek Resources (USA) Inc. and Ivanhoe Energy (USA) Inc. dated January 15, 2004 (Incorporated by reference to Exhibit 10.21 of Form 10-K filed with the Securities and Exchange Commission on March 15, 2004)
10.17	Farm-out Agreement by and among Richfirst Holdings Limited, Pan-China Resources Limited, Sunwing Energy Ltd. and the Company dated January 18, 2004 (Incorporated by reference to Exhibit 10.22 of Form 10-K filed with the Securities and Exchange Commission on March 15, 2004)
10.18	Farmout and Exploration Agreement, Knights Landing Starkey Sand Development Program between Ivanhoe Energy (USA) Inc. and Nahabedian Exploration Group, LLC dated February 17, 2004 (Incorporated by reference to Exhibit 10.23 of Form 10-K filed with the Securities and Exchange Commission on March 15, 2004)
10.19	Agreement and Plan of Merger dated December 11, 2004 by and among Ivanhoe Energy Inc., Ivanhoe Merger Sub, Inc. and Ensyn Group, Inc. (Incorporated by reference to Exhibit 2.1 of Form 8-K filed with the Securities and Exchange Commission on December 15, 2004)
10.20	Voting Agreement dated December 11, 2004 by and by and among Ivanhoe Energy Inc, Ensyn Group, Inc. and Robert M. Friedland. (Incorporated by reference to Exhibit 99.1 of Form 10-K filed with the Securities and Exchange Commission on December 15, 2004)
10.21	Employment Agreement dated April 30, 2002 between Ivanhoe Energy Inc. and E. Leon Daniel
10.22	Employment Agreement dated November 25, 2003 between Ivanhoe Energy Inc. and W. Gordon Lancaster
14.1	Code of Business Conduct and Ethics (Incorporated by reference to Exhibit 14.1 of Form 10-K filed with the SEC on March 15, 2004)
21.1	Subsidiaries of Ivanhoe Energy Inc.
23.1	Consent of Gilbert Laustsen Jung Associates Ltd., Petroleum Engineers
23.2	Consent of Netherland, Sewell & Associates, Inc.
23.3	Consent of Deloitte & Touche LLP
31.1	Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification by the Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification by the Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

(b) **Reports on Form 8-K:**

December 11, 2004	Agreement and Plan of Merger with Ensyn Group, Inc., a Delaware corporation

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

IVANHOE ENERGY INC.

By: /s/ E. Leon Daniel
Name: E. Leon Daniel
Title: President and Chief Executive Officer Dated: March 3, 2005

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ E. LEON DANIEL E. Leon Daniel	President, Chief Executive Officer and Director (Principal Executive Officer)	March 3, 2005
/s/ W. GORDON LANCASTER W. Gordon Lancaster	Chief Financial Officer (Principal Financial and Accounting Officer)	March 3, 2005
/s/ DAVID R. MARTIN David Martin	Chairman of the Board and Director	March 3, 2005
/s/ ROBERT M. FRIEDLAND Robert M. Friedland	Deputy Chairman and Director	March 3, 2005
/s/ JOHN A. CARVER John A. Carver	Director	March 3, 2005
/s/ R. EDWARD FLOOD R. Edward Flood	Director	March 3, 2005
/s/ SHUN-ICHI SHIMIZU Shun-ichi Shimizu	Director	March 3, 2005
/s/ HOWARD R. BALLOCH Howard Balloch	Director	March 3, 2005
/s/ J. STEVEN RHODES J. Steven Rhodes	Director	March 3, 2005

EXHIBIT 31.1

CERTIFICATION BY THE CHIEF EXECUTIVE OFFICER
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, E. Leon Daniel, certify that:

1. I have reviewed this Annual Report on Form 10-K of Ivanhoe Energy Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
    a.) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b.) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    c.) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors:
    a.) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b.) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

* * *

Date: March 3, 2005

Chief Executive Officer

By: /s/ E. Leon Daniel

E. Leon Daniel

EXHIBIT 31.2

CERTIFICATION BY THE CHIEF FINANCIAL OFFICER
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, W. Gordon Lancaster, certify that:

1. I have reviewed this Annual Report on Form 10-K of Ivanhoe Energy Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
    a.) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b.) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    c.) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors:
    a.) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b.) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

* * *

Date: March 3, 2005

Chief Financial Officer

By: /s/ W. Gordon Lancaster

W. Gordon Lancaster

CERTIFICATION BY THE
CHIEF EXECUTIVE OFFICER PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, E. Leon Daniel, Chief Executive Officer, of Ivanhoe Energy Inc, hereby certify that:

(a) our periodic report on Form 10-K for the year ended December 31, 2004 (the "**Form 10-K**"), fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended, and related interpretations; and

(b) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and our results of operations.

* * *

Chief Executive Officer

By: /s/ E. Leon Daniel

E. Leon Daniel

March 3, 2005

EXHIBIT 32.2

CERTIFICATION BY THE
CHIEF FINANCIAL OFFICER PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, W. Gordon Lancaster, Chief Financial Officer, of Ivanhoe Energy Inc., hereby certify that:

(a) our periodic report on Form 10-K for the year ended December 31, 2004 (the "**Form 10-K**"), fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended, and related interpretations; and

(b) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and our results of operations.

* * *

Chief Financial Officer

By: /s/ W. Gordon Lancaster

W. Gordon Lancaster

Date: March 3, 2005

EXHIBIT INDEX

Exhibit No.	Description
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10.1	Petroleum Contract for Kongnan Block, Dagang Oilfield of the People's Republic of China dated September 8, 1997 between China National Petroleum Corporation and Pan-China Resources Ltd., as amended June 11, 1999 (Incorporated by reference to Exhibit 3.15 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000)
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	December 15, 2004)
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32.1	Certification by the Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification by the Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

(b) Reports on Form 8-K:

December 11, 2004 Agreement and Plan of Merger with Ensyn Group, Inc., a Delaware corporation